USA Compression Partners, LP
Form 424B4
January 16, 2013

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Filed pursuant to Rule 424(b)(4)
Registration No. 333-174803

PROSPECTUS

USA Compression Partners, LP

11,000,000 Common Units

Representing Limited Partner Interests

This is the initial public offering of our common units. We are offering 11,000,000 common units in this offering. No public market currently exists for our common units. Our initial public offering price is $18.00 per common unit. Our common units have been approved for listing (subject to official notice of issuance) on the New York Stock Exchange under the symbol "USAC".

Investing in our common units involves risks. Please read "Risk Factors" beginning on page 25 of this prospectus.

These risks include the following:

- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay our minimum quarterly distributions to holders of our common units and subordinated units.
- A long-term reduction in the demand for or production of natural gas or crude oil in the locations where we operate could adversely affect the demand for our services or the prices we charge for our services, which could result in a decrease in our revenues and cash available for distribution to our unitholders.
- We have several key customers. The loss of any of these customers would result in a decrease in our revenues and cash available for distribution to our unitholders.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Our general partner and its affiliates have conflicts of interest with us and limited fiduciary duties and they may favor their own interests to the detriment of us and our common unitholders.

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

We are an "emerging growth company" within the meaning of the federal securities laws and will be eligible for reduced reporting requirements.

	Per Common Unit	Total
Public Offering Price	$ 18.0000	$ 198,000,000
Underwriting Discounts and Commissions(1)	$ 1.1025	$ 12,127,500
Proceeds to USA Compression Partners, LP (before expenses)	$ 16.8975	$ 185,872,500

(1) Excludes a structuring fee of 0.375% of the gross proceeds of this offering payable to Barclays Capital Inc. and Goldman, Sachs & Co. Incorporated. Please see "Underwriting."

We have granted the underwriters a 30-day option to purchase up to an additional 1,650,000 common units on the same terms and conditions as set forth above if the underwriters sell more than 11,000,000 common units in this offering.

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.

The underwriters expect to deliver the common units on or about January 18, 2013.

Barclays **Goldman, Sachs & Co.** **J.P. Morgan** **Wells Fargo Securities**

Raymond James **RBC Capital Markets** **UBS Investment Bank** **Evercore Partners**

January 14, 2013

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You should rely only on the information contained in this prospectus, any free writing prospectus prepared by or on behalf of us or any other information to which we have referred you in connection with this offering. We have not, and the underwriters have not, authorized any other person to provide you with information different from that contained in this prospectus. Neither the delivery of this prospectus nor the sale of common units means that information contained in this prospectus is correct after the date of this prospectus. This prospectus is not an offer to sell or the solicitation of an offer to buy the common units in any circumstances under which the offer or solicitation is unlawful.

Until February 8, 2013 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. This summary does not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including the historical and pro forma financial statements and the notes to those financial statements included in this prospectus. You should read "Risk Factors" for more information about important risks that you should consider carefully before buying our common units. We include a glossary of some of the terms used in this prospectus as Appendix B.

References in this prospectus to "USA Compression," "we," "our," "us," "the Partnership" or like terms refer to USA Compression Partners, LP and its wholly owned subsidiaries, including USA Compression Partners, LLC ("USAC Operating"). References to "USA Compression Holdings" refer to USA Compression Holdings, LLC, the owner of USA Compression GP, LLC, our general partner. References to "Riverstone" refer to Riverstone/Carlyle Global Energy and Power Fund IV, L.P., and affiliated entities, including Riverstone Holdings LLC.

Overview

We are a growth-oriented Delaware limited partnership and, based on management's significant experience in the industry, we believe we are one of the largest independent providers of compression services in the U.S. in terms of total compression unit horsepower. As of September 30, 2012, we had 889,099 horsepower in our fleet and 31,630 horsepower on order for delivery, of which 23,135 horsepower has been delivered as of November 30, 2012 and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013. We employ a customer-focused business philosophy in partnering with our diverse customer base, which is comprised of producers, processors, gatherers and transporters of natural gas. Natural gas compression, a mechanical process whereby natural gas is compressed to a smaller volume resulting in a higher pressure, is an essential part of the production and transportation of natural gas. As part of our services, we engineer, design, operate, service and repair our compression units and maintain related support inventory and equipment. The compression units in our modern fleet are designed to be easily adaptable to fit our customers' dynamic compression requirements. By focusing on the needs of our customers and by providing them with reliable and flexible compression services, we are able to develop long-term relationships, which lead to more stable cash flows for our unitholders. From 2003 through the third quarter of 2012, our average horsepower utilization was over 90%. We have been providing compression services since 1998.

We focus primarily on large-horsepower infrastructure applications. As of September 30, 2012, we estimate that over 90% of our revenue generating horsepower was deployed in large-volume gathering systems, processing facilities and transportation applications. We utilize a modern fleet, with an average age of our compression units of approximately five years. Our standard new-build compression unit is generally configured for multiple compression stages, allowing us to operate our units across a broad range of operating conditions. This flexibility allows us to enter into longer-term contracts and reduces the redeployment risk of our horsepower in the field. Our modern and standardized fleet, decentralized field-level operating structure and technical proficiency in predictive and preventive maintenance and overhaul operations have enabled us to achieve average service run times consistently above the levels required by our customers.

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The following table provides a summary of our compression units by horsepower as of September 30, 2012 (including additional new compression unit horsepower on order for delivery between October 2012 and December 2012):

Unit Horsepower	Fleet Horsepower	Horsepower on Order(1)	Total Horsepower(2)	Percentage of Total Horsepower
<500	141,354	2,250	143,604	15.6%
>500 <1,000	114,540	1,380	115,920	12.6%
>1,000	633,205	28,000	661,205	71.8%
Total	889,099	31,630	920,729	100.0%

(1) As of November 30, 2012, 23,135 horsepower has been delivered and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013.

(2) Comprised of 1,175 compression units, including 26 new compression units on order.

We generally provide compression services to our customers under long-term, fixed-fee contracts, with initial contract terms of up to five years. We typically continue to provide compression services to our customers beyond their initial contract terms, either through contract renewals or on a month-to-month basis. Our customers are typically required to pay our monthly fee even during periods of limited or disrupted natural gas flows, which enhances the stability and predictability of our cash flows. We are not directly exposed to natural gas price risk because we do not take title to the natural gas we compress and because the natural gas used as fuel by our compression units is supplied by our customers without cost to us.

We provide compression services primarily in shale plays, including the Fayetteville, Marcellus, Woodford, Barnett, Eagle Ford and Haynesville shales. We believe compression services for shale production will increase in the future. According to the Annual Energy Outlook 2013 Early Release prepared by the U.S. Energy Information Administration, or EIA, natural gas production from shale formations will increase from 34% of total U.S. natural gas production in 2011 to 50% of total U.S. natural gas production in 2040. Not only are the production and transportation volumes in these and other shale plays increasing, but the geological and reservoir characteristics of these shales are also particularly attractive for compression services. The changes in production volume and pressure of shale plays over time result in a wider range of compression requirements than in conventional basins. We believe we are well-positioned to meet these changing operating conditions as a result of the flexibility of our compression units. While our business focus is largely compression serving shale plays, we also provide compression services in more mature conventional basins. These conventional basins require increasing amounts of compression as they age and pressures decline, which we believe will provide an additional source of stable and growing cash flows for our unitholders.

For the year ended December 31, 2011, our business generated revenues, net income and net income before interest, taxes, depreciation and amortization, and certain other adjustments, or Adjusted EBITDA, of $98.7 million, $0.1 million and $51.3 million, respectively. For the nine months ended September 30, 2012, our business generated revenues, net income and Adjusted EBITDA of $87.0 million, $3.6 million and $46.7 million, respectively. Please read " Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA, which is a non-GAAP financial measure, and a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with generally accepted accounting principles, or GAAP.

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Natural Gas Compression Fundamentals

Demand for our compression services is directly linked to the production and consumption of natural gas. We believe we will be able to build our business organically by capitalizing on the following positive long-term fundamentals for the domestic natural gas compression services industry:

- Natural gas is a critical component of energy supply in the U.S., accounting for approximately 25% of all energy used in the U.S. in 2011, according to the EIA Annual Energy Outlook 2013 Early Release.

- The EIA forecasts in its Annual Energy Outlook 2013 Early Release that natural gas consumption in the U.S. will increase approximately 21% from 2011 to 2040.

- New sources of natural gas are necessary not only to accommodate this increase in demand, but also to offset an established trend of declining production from maturing and aging basins that historically dominated U.S. natural gas production.

  - The EIA estimates that natural gas production from shale formations will increase from 34% of total U.S. natural gas production in 2011 to 50% of total U.S. natural gas production in 2040.

  - Due to the production profile of wells in these shale formations, producers are generally able to continue to produce natural gas economically across varying commodity price environments.

- Natural gas producers, processors, gatherers and transporters have continued to outsource some or all of their natural gas compression requirements.

  - Outsourced compression services enable our customers to meet their changing compression needs more efficiently over time while limiting their capital investments in compression equipment and the cost of specialized employees.

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability and growth of our business. We expect to achieve this objective by executing on the following strategies:

- ***Capitalize on the increased need for natural gas compression in conventional and unconventional plays.*** We expect additional demand for compression services to result from the continuing shift of natural gas production to domestic shale plays as well as the declining production pressures of aging conventional basins. Our fleet of modern, flexible compression units, which are capable of being rapidly deployed and redeployed and many of which are designed to operate in multiple compression stages, will enable us to capitalize on opportunities both in these emerging shale plays as well as conventional fields.

- ***Continue to execute on attractive organic growth opportunities.*** Between 2003 and 2011, we grew the horsepower in our fleet of compression units at a compound annual growth rate of 23% and grew our compression revenues at a compound annual growth rate of 24%, primarily through organic growth. We believe organic growth opportunities will continue to be our most attractive source of near-term growth. We seek to achieve continued organic growth by (i) increasing our business with existing customers, (ii) obtaining new customers in our existing areas of operations and (iii) expanding our operations into new geographic areas.

Partner with customers who have significant compression needs. We actively seek to identify customers with major acreage positions in active and growing areas. We work with these customers to jointly develop long-term and adaptable solutions designed to optimize their lifecycle compression costs. We believe this is important in determining the overall economics of producing, gathering and transporting natural gas. Our proactive and collaborative approach positions us to serve as our customers' compression provider of choice.

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Pursue accretive acquisition opportunities. While our principal growth strategy will be to continue to grow organically, we may pursue accretive acquisition opportunities, including the acquisition of complementary businesses, participation in joint ventures or purchase of compression units from existing or new customers in conjunction with providing compression services to them. We will consider opportunities that (i) are in our existing geographic areas of operations or new, high-growth regions, (ii) meet internally established economic thresholds and (iii) may be financed on reasonable terms. We have reviewed potential acquisition opportunities in the past, and will continue to do so in the future, but to date have not actively pursued any acquisitions.

Maintain financial flexibility. We intend to maintain financial flexibility to be able to take advantage of growth opportunities. Historically, we have utilized our cash flow from operations, borrowings under available debt facilities and operating leases to fund capital expenditures to expand our compression services business. This approach has allowed us to significantly grow our fleet and the amount of cash we generate, while maintaining our debt at levels we believe are manageable for our business. Pro forma for this offering, we would have had $298.6 million in borrowing capacity available under our revolving credit facility as of September 30, 2012. We believe our financial flexibility positions us to take advantage of future growth opportunities without incurring debt beyond appropriate levels.

Competitive Strengths

We believe that we are well positioned to successfully execute our business strategies and achieve our principal business objective because of the following competitive strengths:

Stable and growing fee-based cash flows. We charge our customers a fixed monthly fee for our compression services, regardless of the volume of natural gas we compress in that month. Our contracts have initial terms of up to five years and typically extend beyond their initial contract terms, either through contract renewals or on a month-to-month basis. We believe the long-term nature of our fixed-fee contracts enhances our ability to generate stable cash flows and mitigates our exposure to short-term volatility in natural gas and crude oil commodity prices. Our focus on large-horsepower compression installations associated with large-volume gathering and transportation-related applications also mitigates our exposure to the higher volatility associated with smaller wellhead applications.

Modern and efficient large-horsepower compression fleet with multi-stage compression capabilities that can be rapidly and efficiently deployed or relocated. We maintain and utilize a modern, flexible and reliable fleet of compression units to provide compression services. As of September 30, 2012, approximately 84% of our fleet by horsepower (including compression units on order) was comprised of units with greater than 500 horsepower. Our compression units are built on a standardized equipment package and have an average age of approximately five years. Approximately 69% of our fleet horsepower as of September 30, 2012 was comprised of convertible multi-stage compression units. The flexible configuration of our units enables us to quickly and effectively adapt to changing field conditions, allowing us to render our compression services across a broad range of operating conditions without the need to replace equipment. This adaptability results in lower downtime and operating costs for our customers, generally allowing us to obtain longer-term contracts and provide our compression services more efficiently within fields and across geographies.

Long-standing and strategic customer relationships. We have developed long-standing and strategic customer relationships by consistently delivering outstanding service run time and superior service, and by effectively adapting to our customers' specific and continually changing compression needs. Our top ten customers for the year ended December 31, 2011 accounted for 53% of our revenues for the year and have contracted compression services from us for an average of nine years. Of these all have been customers for at least six years and six have been customers for over ten years. These relationships provide a strong platform for continued organic growth as we respond to our customers' increasing and dynamic natural gas compression needs.

Broad geographic presence in key domestic markets. Our primary business focus is providing compression services in high-growth shale plays where typically steep declines in production volumes and changes in production pressures require significant compression. We also provide compression services in more mature conventional basins that will require increasing amounts of compression as these fields age and pressures decline.

Experienced management team with a proven ability to deliver strong organic growth. Our Chief Executive Officer, Eric D. Long, co-founded our company and has over 20 years of experience in the compression industry. The members of our management team have an average of over 25 years of experience in energy and service industries, and several key executive members of our sales and operating team have worked together for over 14 years. Our organic growth has resulted from our management's commitment to optimize compression lifecycle cost for our customers by delivering outstanding customer service.

Supportive sponsor with significant industry expertise. Riverstone is the principal owner of our general partner. Riverstone has substantial experience as a private equity investor in master limited partnerships, with current or prior investments in the general partners or managing members of Buckeye Partners, L.P., Kinder Morgan Energy Partners, L.P., Magellan Midstream Partners, L.P. and Niska Gas Storage Partners LLC. Riverstone's management has substantial experience in identifying, evaluating, negotiating and financing acquisitions and investments. By providing us with strategic guidance and financial expertise, we believe our relationship with Riverstone will greatly enhance our ability to grow our asset base and cash flow.

The compression services business is highly competitive. Some of our competitors have a broader geographic scope, as well as greater financial and other resources than we do. Smaller companies that compete with us may be able to more quickly adapt to changes within our industry and changes in economic conditions as a whole. Additionally, the current availability of attractive financing terms makes the purchase of individual compression units increasingly affordable to our customers. For further discussion of the risks that we face, please read "Risk Factors."

Recent Developments

On June 1, 2012, we amended our revolving credit facility to increase the overall commitments under the facility from $500 million to $600 million. In addition, on June 1, 2012, we entered into a fourth amended and restated credit agreement to, among other things, permit the offering-related transactions. On December 10, 2012, we amended the fourth amended and restated credit agreement to extend the periods during which the maximum funded debt to EBITDA ratio thresholds will apply. We refer to the fourth amended and restated credit agreement, as so amended, as the amended and restated credit agreement. The amended and restated credit agreement will become effective only upon the closing of this offering. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Description of Revolving Credit Facility" for a description of the terms of the amended and restated credit agreement.

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Preliminary Estimate of Selected Fourth Quarter 2012 Financial Results

While financial information and operating data as of and for the three months ended December 31, 2012 are not available, based on the information and data currently available, management estimates, on a preliminary basis, that revenue for the three months ended December 31, 2012 is expected to be between $31.0 million and $32.0 million compared to $28.4 million for the three months ended December 31, 2011 and Adjusted EBITDA is expected to be between $16.4 million and $17.0 million compared to $14.1 million for the three months ended December 31, 2011 (see below for a reconciliation of estimated Adjusted EBITDA to estimated net income, its most directly comparable GAAP financial measure). The estimated increase in our revenue and Adjusted EBITDA for the three months ended December 31, 2012 as compared to the prior year period is primarily due to an increase in revenue generating horsepower in our fleet during the three months ended December 31, 2012. Average revenue generating horsepower for the year ended December 31, 2012 is 749,936. Additionally, management expects costs of operations for the three months ended December 31, 2012 to be between $9.5 million and $9.7 million compared to $11.6 million for the three months ended December 31, 2011 and selling, general, and administrative expenses for the three months ended December 31, 2012 to be between $5.4 million and $5.5 million compared to $4.5 million for the three months ended December 31, 2011. Costs of operations for the three months ended December 31, 2011 were higher because of certain costs related to transactions in our retail service activities that did not recur during the three months ended December 31, 2012. Furthermore, management expects maintenance capital expenditures for the three months ended December 31, 2012 to be between $3.2 million and $3.6 million compared to $2.7 million for the three months ended December 31, 2011. The increase in maintenance capital expenditures is due to the increase in revenue generating horsepower in our fleet during the three months ended December 31, 2012. Our total capital expenditures for the three months ended December 31, 2012 are estimated to be between $24 million and $25 million. Our revolving credit facility balance as of December 31, 2012 was approximately $502.3 million compared to $482 million as of September 30, 2012. These estimates are based on actual results for October and November 2012 and actual contract service operations billings and estimated gross operating margin percentage for December 2012.

We have prepared these estimates on a basis materially consistent with our historical financial results and with our calculation of Adjusted EBITDA as presented in " Summary Historical and Pro Forma Financial and Operating Data". These estimated ranges are preliminary and unaudited and are thus inherently uncertain and subject to change. Given the timing of these estimates, we have not completed our customary quarterly close and review procedures as of and for the three months ended December 31, 2012, and our actual results for this period may differ from these estimates. During the course of the preparation of our consolidated financial statements and related notes as of and for the three months ended December 31, 2012, we may identify items that could cause our final reported results to be different from the preliminary financial estimates presented above. Important factors that could cause actual results to differ from our preliminary estimates are set forth under the headings "Risk Factors" and "Forward-Looking Statements."

These estimates should not be viewed as a substitute for full interim financial statements prepared in accordance with GAAP. In addition, these preliminary estimates for the three months ended December 31, 2012 are not necessarily indicative of the results to be achieved for any future period. We do not expect our consolidated financial statements and related notes as of and for the year ended December 31, 2012 to be publicly announced or filed with the SEC until after this offering is completed.

The following table reconciles Adjusted EBITDA to net income (loss) for the three months ended December 31, 2011 along with the estimated range for the three months ended December 31, 2012.

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The line items in the table for the three months ended December 31, 2012 are estimates and are subject to the qualifications set forth above:

	Three Months Ended December 31, 2011	Three Months Ended December 31, 2012 Low Estimate	Three Months Ended December 31, 2012 High Estimate
	(In millions)		
Net income (loss)	$ 0.0	$ 1.0	$ 1.1
Adjustments:			
Interest expense	3.5	4.1	4.3
Depreciation and amortization	8.7	11.0	11.3
Income taxes	0.0	0.0	0.0
EBITDA	$ 12.2	$ 16.1	$ 16.7
Equipment operating lease expense	0.8		
Riverstone management fee	0.8	0.3	0.3
Restructuring charges	0.3		
Adjusted EBITDA	$ 14.1	$ 16.4	$ 17.0

Our Relationship with Riverstone

Over 97% of the equity in USA Compression Holdings is owned by Riverstone, with the balance owned by our current officers and employees and a small, non-controlling investor. Riverstone, a global energy- and power-focused private equity firm founded in 2000, has raised over $24 billion of assets under management across seven investment funds. Riverstone conducts buyout and growth capital investments in the midstream, exploration and production, energy services, power and renewable sectors of the energy industry. With offices in New York, London and Houston, Riverstone has committed approximately $20.4 billion to 93 investments in North America, Latin America, Europe, Africa, and Asia. As the owner of our general partner, approximately 27% of our outstanding common units, all of our subordinated units and all of our incentive distribution rights, USA Compression Holdings and Riverstone are incentivized to support and promote the successful execution of our business plan.

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Risk Factors

An investment in our common units involves risks. Below is a summary of certain key risk factors that you should consider in evaluating an investment in our common units. This list is not exhaustive. Please read the full discussion of these risks and other risks described under "Risk Factors."

Risks Related to Our Business

- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay our minimum quarterly distributions to holders of our common units and subordinated units.

- The assumptions underlying our estimate of cash available for distribution described in "Our Cash Distribution Policy and Restrictions on Distributions" are inherently uncertain and subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause us to be unable to pay our minimum quarterly distributions to holders of our common units and subordinated units.

- A long-term reduction in the demand for, or production of, natural gas or crude oil in the locations where we operate could adversely affect the demand for our services or the prices we charge for our services, which could result in a decrease in our revenues and cash available for distribution to our unitholders.

- We have several key customers. The loss of any of these customers would result in a decrease in our revenues and cash available for distribution to our unitholders.

- We face significant competition that may cause us to lose market share and reduce our ability to make distributions to our unitholders.

- We depend on a limited number of suppliers and are vulnerable to product shortages and price increases, which could have a negative impact on our results of operations.

- We are subject to substantial environmental regulation, and changes in these regulations could increase our costs or liabilities.

Risks Inherent in an Investment in Us

- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

- Our general partner and its affiliates, including USA Compression Holdings, have conflicts of interest with us and limited fiduciary duties and they may favor their own interests to the detriment of us and our common unitholders.

- Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

You will experience immediate and substantial dilution in pro forma net tangible book value of $8.44 per common unit.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

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The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

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Partnership Structure and Offering-Related Transactions

We were formed in 2008 as a Texas limited partnership and converted to a Delaware limited partnership in 2011. USA Compression Holdings currently holds all of our limited partner interests. In order to maximize operational flexibility, we will conduct our operations through subsidiaries. At or prior to the closing of this offering, the following transactions, which we refer to as the offering-related transactions, will occur:

- we will convert the general partner interest held by USA Compression GP, LLC, our general partner, into a 2.0% general partner interest in us and our incentive distribution rights;

- we will convert the limited partner interest held by USA Compression Holdings into 4,048,588 common units and 14,048,588 subordinated units, representing an aggregate 61.0% limited partner interest in us;

- we will receive net proceeds of $180.7 million from the issuance and sale of 11,000,000 common units to the public, representing a 37.0% limited partner interest in us;

- we will use the net proceeds from this offering in the manner described in "Use of Proceeds"; and

- our amended and restated credit agreement will become effective and, after using the net proceeds from this offering in the manner described in "Use of Proceeds," we would have had $298.6 million of long-term borrowing capacity available to us under the revolving credit facility as of September 30, 2012.

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Organizational Structure After the Offering

The following diagram depicts our organizational structure and ownership after giving effect to this offering and the related offering-related transactions.

Public Common Units	37.0%(1)
Common Units held by USA Compression Holdings	13.7%(1)
Subordinated Units held by USA Compression Holdings	47.3%
Incentive Distribution Rights	(2)
General Partner Interest	2.0%
Total	100.0%

(1) Assumes the underwriters do not exercise their option to purchase additional common units. If the underwriters exercise their option to purchase additional common units in full, the public common units will represent a 40.4% interest in us, the common units held by USA Compression Holdings will represent a 12.8% interest in us and the subordinated units held by USA Compression Holdings will represent a 44.8% interest in us.

(2) Incentive distribution rights represent a potentially variable interest in distributions and thus are not expressed as a fixed percentage. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner Interest and Incentive Distribution Rights."

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Our Management

Our general partner has sole responsibility for conducting our business and for managing our operations and is controlled by USA Compression Holdings, which is controlled by Riverstone. Our general partner will not receive any management fee or other compensation in connection with the management of our business or this offering, but a subsidiary of our general partner will be entitled to reimbursement of all direct and indirect expenses incurred on our behalf, which we expect to be approximately $27.5 million for the year ending December 31, 2013. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

The board of directors of our general partner is initially comprised of six members, all of whom have been designated by USA Compression Holdings and one of whom is independent. In compliance with the rules of the New York Stock Exchange, or the NYSE, a second independent director will be appointed to the board of directors of USA Compression GP, LLC within 90 days of listing and a third independent director will be appointed within twelve months of listing. Neither our general partner nor its board of directors will be elected by our unitholders. USA Compression Holdings is the sole member of our general partner and will have the right to appoint our general partner's entire board of directors, including the independent directors.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 100 Congress Avenue, Suite 450, Austin, Texas 78701 and our telephone number is (512) 473-2662. Our website is located at *www.usacpartners.com* and will be activated in connection with the closing of this offering. We will make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or 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 this prospectus and does not constitute a part of this prospectus.

Summary of Conflicts of Interest and Fiduciary Duties

Our general partner has a legal duty to manage us in a manner beneficial to our partners. This legal duty originates in statutes and judicial decisions and is commonly referred to as a "fiduciary duty." However, the officers and directors of our general partner also have fiduciary duties to manage our general partner in a manner beneficial to its owner, USA Compression Holdings. Certain of the officers and directors of our general partner are also officers and directors of USA Compression Holdings. As a result, conflicts of interest will arise in the future between us and holders of our common units, on the one hand, and USA Compression Holdings and our general partner, on the other hand. For example, our general partner will be entitled to make determinations that affect the amount of distributions we make to the holders of common and subordinated units, which in turn has an effect on whether our general partner receives incentive distributions.

Our partnership agreement limits the liability of, and reduces the fiduciary duties owed by, our general partner to holders of our common units. Our partnership agreement also restricts the remedies available to holders of our common units for actions that might otherwise constitute a breach of our general partner's fiduciary duties. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement each holder of common units consents to various actions and potential conflicts of interest contemplated in the partnership agreement that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

For a more detailed description of the conflicts of interest and the fiduciary duties of our general partner, please read "Conflicts of Interest and Fiduciary Duties."

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Implications of Being an Emerging Growth Company

We are an "emerging growth company" within the meaning of the federal securities laws. For as long as we are an emerging growth company, we will not be 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,
- 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.

We will remain an emerging growth company for five years unless, prior to that time, we have more than $1.0 billion in annual revenues, have a market value for our common units held by non-affiliates of more than $700 million, or issue more than $1.0 billion of non-convertible debt over a three-year period. We may choose to take advantage of some but not all of these reduced obligations. We have availed ourselves of the reduced reporting obligations with respect to executive compensation disclosure in this prospectus, and expect to continue to avail ourselves of the reduced reporting obligations available to emerging growth companies in future filings. For as long as we take advantage of the reduced reporting obligations, the information that we provide unitholders may be different than might be provided by other public companies in which you hold equity interests.

We are also choosing to "opt out" of the extended transition period for complying with new or revised accounting standards available to emerging growth companies, and as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. Under federal securities laws, our decision to opt out of the extended transition period is irrevocable.

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The Offering

Common units offered to the public	11,000,000 common units. 12,650,000 common units, if the underwriters exercise in full their option to purchase additional common units.
Units outstanding after this offering	15,048,588 common units and 14,048,588 subordinated units, representing a 50.7% and 47.3% limited partner interest in us, respectively (or, if the underwriters' option to purchase additional common units is exercised in full, 16,665,588 common units and 14,048,588 subordinated units, representing a 53.2% and a 44.8% limited partnership interest in us, respectively). Our general partner will own a 2.0% general partner interest in us.
Use of proceeds	We will receive net proceeds from the issuance and sale of common units offered by this prospectus of approximately $180.7 million, after deducting underwriting discounts and commissions, structuring fees and offering expenses. We will use the net proceeds from this offering (including the net proceeds from any exercise of the underwriters' option to purchase additional common units) to repay indebtedness outstanding under our revolving credit facility. We will incur indebtedness under our revolving credit facility to fund capital expenditures and for working capital needs. We have incurred indebtedness from time to time under our revolving credit facility to fund capital expenditures and for working capital purposes and on December 15, 2011 we used borrowings under the facility to purchase the compression units previously leased from Caterpillar Financial Services Corporation, or Caterpillar. On June 1, 2012, we amended our revolving credit facility to increase the overall commitments under the facility from $500 million to $600 million and entered into our amended and restated credit facility, which will become effective only upon the closing of this offering, to, among other things, permit the offering-related transactions. At September 30, 2012, the interest rate on amounts borrowed under the revolving credit facility was 3.0%. Affiliates of each of the underwriters participating in this offering are lenders under our revolving credit facility and will receive a substantial portion of the proceeds from this offering pursuant to the repayment of a portion of the borrowings thereunder. Please read "Underwriting FINRA Rules."

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Cash distributions	Our general partner will adopt a cash distribution policy that will require us to pay a minimum quarterly distribution of $0.425 per unit ($1.70 per unit on an annualized basis) to the extent we have sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. We refer to this cash as "available cash," and it is defined in our partnership agreement included in this prospectus as Appendix A and in the glossary included in this prospectus as Appendix B. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more detail under the caption "Our Cash Distribution Policy and Restrictions on Distributions." For the first quarter that we are publicly traded, we will pay a prorated distribution covering the period from the completion of this offering through March 31, 2013, based on the actual length of that period. Our partnership agreement requires that we distribute all of our available cash each quarter in the following manner: *first*, 98.0% to the holders of common units and 2.0% to our general partner, until each common unit has received the minimum quarterly distribution of $0.425, plus any arrearages from prior quarters; *second*, 98.0% to the holders of subordinated units and 2.0% to our general partner, until each subordinated unit has received the minimum quarterly distribution of $0.425; and *third*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unit has received a distribution of $0.4888 If cash distributions to our unitholders exceed $0.4888 per unit in any quarter, our general partner will receive, in addition to distributions on its 2.0% general partner interest, increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions." Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions." The amount of pro forma available cash generated during the year ended December 31, 2011 would have been sufficient to allow us to pay the full minimum quarterly distribution on all common units and a cash distribution of $0.124 per quarter ($0.495 on an annualized basis), or approximately 30.5% of the minimum quarterly distribution, on all of our subordinated units for such period.

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	The amount of pro forma available cash generated during the twelve months ended September 30, 2012 would have been sufficient to allow us to pay the full minimum quarterly distribution on all common units and a cash distribution of \$0.168 per quarter (\$0.671 on an annualized basis), or approximately 40.7% of the minimum quarterly distribution, on all of our subordinated units for such period. We believe that, based on our estimated cash available for distribution as described under the caption "Our Cash Distribution Policy and Restrictions on Distributions," we will have sufficient cash available for distribution to pay the minimum quarterly distribution of \$0.425 per unit on all common and subordinated units and the corresponding distributions on our general partner's 2.0% interest for the four-quarter period ending December 31, 2013. This estimate is based in part on the assumption that we will institute a distribution reinvestment plan, or DRIP, following completion of this offering, and that USA Compression Holdings will reinvest under the DRIP all distributions it receives on its common and subordinated units in additional newly issued common units, and that our general partner will make capital contributions to maintain its 2.0% general partner interest in us. We have not assumed participation in the DRIP by any public unit holder. Please read "Risk Factors" and "Our Cash Distribution Policy and Restrictions on Distributions."
Subordinated units	USA Compression Holdings will initially own all of our subordinated units. The principal difference between our common and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages.
Conversion of subordinated units	The subordination period will end on the first business day after we have earned and paid at least (i) \$1.70 (the minimum quarterly distribution on an annualized basis) on each outstanding unit and the corresponding distribution on our general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2015 or (ii) \$2.55 (150.0% of the annualized minimum quarterly distribution) on each outstanding unit and the corresponding distributions on our general partner's 2.0% interest and the related distribution on the incentive distribution rights for the four-quarter period immediately preceding that date.

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	When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages. For a description of the subordination period, please read "Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period."
General Partner's right to reset the target distribution levels	Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on the same percentage increases above the reset minimum quarterly distribution. If our general partner elects to reset the target distribution levels, it will be entitled to receive common units and to maintain its general partner interest. The number of common units to be issued to our general partner will equal the number of common units that would have entitled the holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner's Right to Reset Incentive Distribution Levels."
Issuance of additional units	We can issue an unlimited number of units without the consent of our unitholders. Please read "Units Eligible for Future Sale" and "The Partnership Agreement Issuance of Additional Partnership Units."
Limited voting rights	Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business. Our unitholders will have no right to elect our general partner or its directors on an annual or continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding units voting together as a single class, including any units owned by our general partner and its affiliates, including USA Compression Holdings. Upon consummation of this offering, USA Compression Holdings will own an aggregate of 62.2% of our common and subordinated units (or 58.8% if the underwriters' option to purchase additional common units is exercised in full). This will give USA Compression Holdings the ability to prevent the involuntary removal of our general partner. Please read "The Partnership Agreement Voting Rights."

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Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price that is not less than the then-current market price of the common units, as calculated pursuant to the terms of our partnership agreement. At the end of the subordination period (which could occur as early as December 31, 2013), assuming no additional issuances of common units (other than upon the conversion of the subordinated units), USA Compression Holdings will own an aggregate of approximately 62.2% of our outstanding common units. Following completion of this offering, we intend to institute a DRIP. USA Compression Holdings has informed us that it intends to reinvest under the DRIP all distributions it receives on its common and subordinated units. To the extent that USA Compression Holdings participates in the DRIP, its percentage ownership of us will increase relative to public unit holders that do not participate in the DRIP. For additional information about this right, please read "The Partnership Agreement Limited Call Right."
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2015, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 20% or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.70 per unit, we estimate that your average allocable federal taxable income per year will be no more than $0.34 per unit. Please read "Material Federal Income Tax Consequences Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions."
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the U.S., please read "Material Federal Income Tax Consequences." All statements of legal conclusions contained in "Material Federal Income Tax Consequences," unless otherwise noted, are the opinion of Latham & Watkins LLP with respect to the matters discussed therein.
Exchange listing	Our common units have been approved for listing (subject to official notice of issuance) on the NYSE under the symbol "USAC".

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Summary Historical and Pro Forma Financial and Operating Data

The following table presents our summary historical financial and operating data and pro forma financial data for the periods and as of the dates presented. The following table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical and pro forma financial statements and accompanying notes included elsewhere in this prospectus.

The summary historical financial and operating data has been prepared on the following basis:

- the historical financial information as of December 31, 2010 and 2011 and for the years ended December 31, 2009, 2010 and 2011 is derived from our audited financial statements, which are included elsewhere in this prospectus;

- the historical financial information as of December 31, 2009 is derived from our audited financial statements, which are not included in this prospectus;

- the historical financial information as of September 30, 2012 and for the nine months ended September 30, 2011 and September 30, 2012 is derived from our unaudited financial statements, which are included elsewhere in this prospectus; and

- the historical financial information as of September 30, 2011 is derived from our unaudited financial statements, which are not included in this prospectus.

We were acquired by USA Compression Holdings on December 23, 2010, which we refer to as the Holdings Acquisition. In connection with this acquisition, our assets and liabilities were adjusted to fair value on the closing date by application of "push-down" accounting. Due to these adjustments, our audited consolidated financial statements are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (i) the periods prior to the acquisition date for accounting purposes, using a date of convenience of December 31, 2010, are identified as "Predecessor," and (ii) the periods from December 31, 2010 forward are identified as "Successor." Please read note 1 to our audited financial statements as of December 31, 2011 included elsewhere in this prospectus.

The summary pro forma financial information for the year ended December 31, 2011 and as of and for the nine months ended September 30, 2012 is derived from our unaudited pro forma financial statements included elsewhere in this prospectus. The pro forma adjustments have been prepared as if the transactions described below had taken place on September 30, 2012, in the case of the pro forma balance sheet, or as of January 1, 2011, in the case of the pro forma statement of operations for the year ended December 31, 2011 and for the nine months ended September 30, 2012. These transactions include:

- the entry into the second amendment to our revolving credit facility on November 16, 2011;

- the entry into the third amendment to our revolving credit facility on June 1, 2012 and the effectiveness of our amended and restated credit agreement, which we entered into on June 1, 2012 and amended on December 10, 2012;

- the conversion of our limited partner interests held by USA Compression Holdings into 4,048,588 of our common units and 14,048,588 of our subordinated units;

- the conversion of our general partner interest held by USA Compression GP, LLC, our general partner, into a 2.0% general partner interest in us;

- the issuance by us of all of our incentive distribution rights to USA Compression GP, LLC; and the issuance by us of 11,000,000 common units to the public in exchange for net proceeds of approximately $180.7 million, all of which will be used to repay indebtedness outstanding under our revolving credit facility.

The pro forma financial information should not be considered as indicative of the historical results we would have had or the results we will have after this offering.

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The following table includes the non-GAAP financial measure of Adjusted EBITDA. We define Adjusted EBITDA as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read " Non-GAAP Financial Measures."

	Historical					Pro Forma	
	Predecessor		Successor(1)				
	Year Ended December 31,		Year Ended December 31,	Nine Months Ended September 30,	Nine Months Ended September 30,	Year Ended December 31,	Nine Months Ended September 30,
	2009	2010	2011	2011	2012	2011	2012
	(in thousands, except per unit and operating data)						
Revenues:							
Contract operations	$ 93,178	$ 89,785	$ 93,896	$ 68,762	$ 85,285	$ 93,896	$ 85,285
Parts and service	2,050	2,243	4,824	1,565	1,730	4,824	1,730
Total revenues	95,228	92,028	98,720	70,327	87,015	98,720	87,015
Costs and expenses:							
Cost of operations, exclusive of depreciation and amortization	30,096	33,292	39,605	28,057	27,928	39,605	27,928
Selling, general and administrative(2)	9,136	11,370	12,726	8,500	12,927	12,726	12,927
Restructuring charges(3)			300			300	
Depreciation and amortization	22,957	24,569	32,738	24,044	30,590	32,738	30,590
(Gain) loss on sale of assets	(74)	(90)	178	159	257	178	257
Impairment of compression equipment	1,677						
Total costs and expenses	63,792	69,141	85,547	60,760	71,702	85,547	71,702
Operating income	31,436	22,887	13,173	9,567	15,313	13,173	15,313
Other income (expense):							
Interest expense	(10,043)	(12,279)	(12,970)	(9,424)	(11,637)	(6,303)	(7,808)
Other	25	26	21	17	23	21	23
Total other expense	(10,018)	(12,253)	(12,949)	(9,407)	(11,614)	(6,282)	(7,785)
Income before income tax expense	21,418	10,634	224	160	3,699	6,891	7,528
Income tax expense(4)	190	155	155	111	144	155	144
Net income	$ 21,228	$ 10,479	$ 69	$ 49	$ 3,555	$ 6,736	$ 7,384
Adjusted EBITDA	$ 56,917	$ 51,987	$ 51,285	$ 37,162	$ 46,676	$ 51,285	$ 46,676
Pro forma net income per limited partner unit:							
Common unit							
Subordinated unit							

Other Financial Data:						
Capital expenditures(5)	$ 29,580	$ 18,886	$ 133,264	$ 65,153	$ 148,473	
Cash flows provided by (used in):						
Operating activities	42,945	38,572	33,782	28,673	30,375	
Investing activities	(26,763)	(18,768)	(140,444)	(64,379)	(147,121)	
Financing activities	(16,545)	(19,804)	106,662	35,706	116,749	
Operating Data (at period end, except averages) unaudited						
Fleet horsepower(6)	582,530	609,730	722,201	691,545	889,099	
Total available horsepower(7)	582,530	612,410	809,418	711,463	902,164	
Revenue generating horsepower(8)	502,177	533,692	649,285	591,290	786,750	
Average revenue generating horsepower(9)	489,243	516,703	570,900	551,566	735,639	
Revenue generating compression units	749	795	888	839	964	
Average horsepower per revenue generating compression unit(10)	655	667	692	683	784	
Horsepower utilization(11)						
At period end	92.0%	91.8%	95.7%	92.8%	93.4%	
Average for the period(12)	92.7%	92.6%	92.3%	91.4%	95.0%	

	Predecessor		**Successor(1)**			**Pro Forma**
Balance Sheet Data (at period end):						
Working capital(13)	$ (4,678)	$ (3,984)	$ (11,295)	$ (11,120)	$ (9,585)	$ (9,585)
Total assets	352,757	614,718	727,876	654,607	849,824	849,974
Long-term debt	260,470	255,491	363,773	291,544	482,137	301,559
Partners' capital	72,626	338,954	339,023	339,003	342,578	523,306

(1) Reflects the push-down of the purchase accounting for the Holdings Acquisition.

(2) Pro forma selling, general and administrative expense does not include incremental general and administrative expenses we expect to incur as a result of being a publicly traded partnership. We expect these expenses to total approximately $3.1 million per year.

(3) During the year ended December 31, 2011, we incurred $0.3 million of restructuring charges for severance and retention benefits related to the termination of certain administrative employees. These charges are reflected as restructuring charges in our consolidated statement of operations. We paid approximately $0.1 million of these restructuring charges in the three months ended March 31, 2012, and paid the remaining $0.2 million in the three-month period ending June 30, 2012.

(4) This represents the Texas franchise tax (applicable to income apportioned to Texas) which, in accordance with Financial Accounting Standards Board Accounting Standards Codification 740 "Income Taxes," or ASC 740, is classified as income tax for reporting purposes.

(5) On December 15, 2011, we purchased all the compression units previously leased from Caterpillar for $43 million and terminated all the lease schedules and covenants under the facility. This amount is included in capital expenditures for the year ended December 31, 2011. On December 16, 2011, the Partnership entered into an agreement with a compression equipment supplier to reduce certain previously made progress payments from $10 million to $2 million. The Partnership applied this $8 million credit to new compression unit purchases from this supplier in the nine months ended September 30, 2012. Before the application of this credit, capital expenditures were $156.4 million for the nine months ended September 30, 2012.

(6) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes any units on order). As of September 30, 2012, we had 31,630 of additional new compression unit horsepower on order, of which 23,135 horsepower has been delivered as of November 30, 2012 and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013.

(7) Total available horsepower is revenue generating horsepower under contract for which we are billing a customer, horsepower in our fleet that is under contract but is not yet generating revenue, horsepower not yet in our fleet that is under contract not yet generating revenue that is subject to a purchase order and idle horsepower. Total available horsepower excludes new horsepower on order for which we do not have a compression services contract.

(8) Revenue generating horsepower is horsepower under contract for which we are billing a customer.

(9) Calculated as the average of the month-end revenue generating horsepower for each of the months in the period.

(10) Calculated as the average of the month-end horsepower per revenue generating compression unit for each of the months in the period.

(11) Horsepower utilization is calculated as (i)(a) revenue generating horsepower plus (b) horsepower in our fleet that is under contract, but is not yet generating revenue plus (c) horsepower not yet in our fleet that is under contract not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Horsepower utilization based on revenue generating horsepower and fleet horsepower at each applicable period end was 86.2%, 87.5% and 89.9% for the years ended December 31, 2009, 2010 and 2011, respectively, and 85.5% and 88.5% for the nine months ended September 30, 2011 and 2012, respectively.

(12) Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period.

(13) Working capital is defined as current assets minus current liabilities.

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Non-GAAP Financial Measures

We include in this prospectus the non-GAAP financial measure of Adjusted EBITDA. We view Adjusted EBITDA as one of our primary management tools, and we track this item on a monthly basis both as an absolute amount and as a percentage of revenue compared to the prior month, year-to-date and prior year and to budget. We define Adjusted EBITDA as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. Adjusted EBITDA is used as a supplemental financial measure by our management and external users of our financial statements, such as investors and commercial banks, to assess:

- the financial performance of our assets without regard to the impact of financing methods, capital structure or historical cost basis of our assets;
- the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;
- the ability of our assets to generate cash sufficient to make debt payments and to make distributions; and
- our operating performance as compared to those of other companies in our industry without regard to the impact of financing methods and capital structure.

We believe that Adjusted EBITDA provides useful information to investors because, when viewed with our GAAP results and the accompanying reconciliations, it provides a more complete understanding of our performance than GAAP results alone. We also believe that external users of our financial statements benefit from having access to the same financial measures that management uses in evaluating the results of our business.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, our Adjusted EBITDA as presented may not be comparable to similarly titled measures of other companies.

Adjusted EBITDA does not include interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. Because we borrow money under our revolving credit facility and have historically utilized operating leases to finance our operations, interest expense and operating lease expense are necessary elements of our costs. Because we use capital assets, depreciation and impairment of compression equipment is also a necessary element of our costs. Expense related to share-based compensation expense related to equity awards to employees is also necessary to operate our business. Therefore, measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income and net cash provided by operating activities determined under GAAP, as well as Adjusted EBITDA, to evaluate our financial performance and our liquidity. Our Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities, and these measures may vary among companies. Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating this knowledge into management's decision-making processes.

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The following table reconciles Adjusted EBITDA to net income and net cash provided by operating activities, its most directly comparable GAAP financial measures, for each of the periods presented:

	Historical					Pro Forma	
	Predecessor		Successor				
	Year Ended December 31,		Year Ended December 31,	Nine Months Ended September 30,	Nine Months Ended September 30,	Year Ended December 31,	Nine Months Ended September 30,
	2009	2010	2011	2011	2012	2011	2012
	(in thousands)						
Net income	$ 21,228	$ 10,479	$ 69	$ 49	$ 3,555	$ 6,736	$ 7,384
Interest expense	10,043	12,279	12,970	9,424	11,637	6,303	7,808
Depreciation and amortization	22,957	24,569	32,738	24,044	30,590	32,738	30,590
Income taxes	190	155	155	111	144	155	144
Impairment of compression equipment(1)	1,677						
Share-based compensation expense	269	382					
Equipment operating lease expense(2)	553	2,285	4,053	3,284		4,053	
Riverstone management fee(3)			1,000	250	750	1,000	750
Restructuring charges(4)			300			300	
Fees and expenses related to the Holdings Acquisition(5)		1,838					
Adjusted EBITDA	$ 56,917	$ 51,987	$ 51,285	$ 37,162	$ 46,676	$ 51,285	$ 46,676
Interest expense	(10,043)	(12,279)	(12,970)	(9,424)	(11,637)		
Income tax expense	(190)	(155)	(155)	(111)	(144)		
Equipment operating lease expense	(553)	(2,285)	(4,053)	(3,284)			
Riverstone management fee			(1,000)	(250)	(750)		
Restructuring charges			(300)				
Fees and expenses related to the Holdings Acquisition		(1,838)					
Other	288	3,362	(920)	(871)	(463)		
Changes in operating assets and liabilities:							
Accounts receivable and advance to employee	1,865	(336)	(976)	(142)	(1,649)		
Inventory	(3,680)	503	1,974	1,102	(950)		
Prepaids	608	(18)	(219)	738	864		
Other non-current assets	(4)	1	(2,601)	(2,143)	(806)		
Accounts payable	(857)	(825)	1,987	1,785	(6,145)		
Accrued liabilities and deferred revenue	(1,406)	455	1,730	4,111	5,379		
Net cash provided by operating activities	$ 42,945	$ 38,572	$ 33,782	$ 28,673	$ 30,375		

(1) Represents non-cash charges incurred to write down long-lived assets with recorded values that are not expected to be recovered through future cash flows.

(2) Represents expenses for the respective periods under the operating lease facility with Caterpillar, from whom we historically leased compression units and other equipment. On December 15, 2011, we purchased the compression units that were previously leased from Caterpillar for $43 million and

terminated all the lease schedules and covenants under the facility. As such, we believe it is useful to investors to view our results excluding these lease payments.

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(3) Represents management fees paid to Riverstone for services performed during 2011 and the nine months ended September 30, 2012. As these fees will not be paid by us following this offering, we believe it is useful to investors to view our results excluding these fees.

(4) During the year ended December 31, 2011, we incurred $0.3 million of restructuring charges for severance and retention benefits related to the termination of certain administrative employees. These charges are reflected as restructuring charges in our consolidated statement of operations. We paid approximately $0.1 million of these restructuring charges in the three months ended March 31, 2012, and paid the remaining $0.2 million in the three months ended June 30, 2012. We believe that it is useful to investors to view our results excluding this non-core expense.

(5) Represents one-time fees and expenses related to the Holdings Acquisition. These fees and expenses are not related to our operations, and we do not expect to incur similar fees or expenses in the future as a publicly traded partnership.

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RISK FACTORS

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in the compression services business. You should consider carefully the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we may be unable to pay the minimum quarterly distribution to our unitholders, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay our minimum quarterly distributions to holders of our common units and subordinated units.

In order to pay our minimum quarterly distribution of $0.425 per unit per quarter, or $1.70 per unit per year, we will require available cash of approximately $12.6 million per quarter, or approximately $50.5 million per year, based on the number of common units, subordinated units and the 2.0% general partner interest to be outstanding immediately after completion of this offering. Under our cash distribution policy, the amount of cash we can distribute to our unitholders principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the level of production of, demand for, and price of natural gas and crude oil, particularly the level of production in the locations where we provide compression services;
- the fees we charge, and the margins we realize, from our compression services;
- the cost of achieving organic growth in current and new markets;
- the level of competition from other companies; and
- prevailing global and regional economic and regulatory conditions, and their impact on our customers.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the levels of our maintenance capital expenditures and expansion capital expenditures;
- the level of our operating costs and expenses;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;

- restrictions contained in our revolving credit facility;
- the cost of acquisitions, if any;
- fluctuations in interest rates;
- our ability to borrow funds and access capital markets; and
- the amount of cash reserves established by our general partner.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read "Our Cash Distribution Policy and Restrictions on Distributions."

On a pro forma basis we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our units for the twelve months ended December 31, 2011 and September 30, 2012.

The amount of cash available for distribution we need to pay the minimum quarterly distribution for four quarters on the common units, the subordinated units and the 2.0% general partner interest to be outstanding immediately after this offering is approximately $50.5 million. Our pro forma cash available for distribution generated during the twelve months ended December 31, 2011 and September 30, 2012 of $33.5 million and $36.0 million, respectively, would have been sufficient to allow us to pay the full minimum quarterly distribution on all of the common units, but would only allow us to pay 30.5% and 40.7%, respectively, of the full minimum quarterly distribution on all of the subordinated units during those periods. For a calculation of our ability to make distributions to unitholders based on our pro forma results for the twelve months ended December 31, 2011 and September 30, 2012, please read "Our Cash Distribution Policy and Restrictions on Distributions Pro Forma Cash Available for Distribution for the Twelve Months Ended December 31, 2011 and September 30, 2012."

The assumptions underlying our estimate of cash available for distribution described in "Our Cash Distribution Policy and Restrictions on Distributions" are inherently uncertain and subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause us to be unable to pay our minimum quarterly distributions to holders of our common units and subordinated units.

Our estimate of cash available for distribution set forth in "Our Cash Distribution Policy and Restrictions on Distributions" is based on assumptions that are inherently uncertain and subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated. The estimate was prepared by our management, and we have not received an opinion or report on it from our independent registered public accounting firm or any other independent auditor. If we do not achieve the estimated results, we may not be able to pay the full minimum quarterly distribution or any amount on our common units or subordinated units, in which event the market price of our common units will likely decline materially.

A long-term reduction in the demand for, or production of, natural gas or crude oil in the locations where we operate could adversely affect the demand for our services or the prices we charge for our services, which could result in a decrease in our revenues and cash available for distribution to our unitholders.

The demand for our compression services depends upon the continued demand for, and production of, natural gas and crude oil. Demand may be affected by, among other factors, natural gas prices, crude oil prices, weather, availability of alternative energy sources, governmental regulation and general demand for energy. Any prolonged, substantial reduction in the demand for natural gas or crude oil would, in all likelihood, depress the level of production activity and result in a decline in the demand for our compression services, which would reduce our cash available for distribution. Lower natural gas prices or crude oil prices over the long term could result in a decline in the production of natural gas or crude oil, respectively, resulting in reduced demand for our compression services. Additionally, production from unconventional natural gas sources, such as tight sands, shales and coalbeds, constitute an increasing percentage of our compression services business. Such sources can be less economically feasible to produce in low natural gas price environments, in part due to costs related to compression requirements, and a reduction in demand for natural gas or natural gas lift for crude oil may cause such sources of natural gas to be uneconomic to drill and produce, which could in turn negatively impact the demand for our services. In addition, governmental regulation and tax policy may impact the demand for natural gas or impact the economic feasibility of development of new natural gas fields or production of existing fields.

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We have several key customers. The loss of any of these customers would result in a decrease in our revenues and cash available for distribution to our unitholders.

We provide compression services under contracts with several key customers. The loss of one of these key customers may have a greater effect on our financial results than for a company with a more diverse customer base. Our largest customer for the year ended December 31, 2011 and nine months ended September 30, 2012 was Southwestern Energy Company and its subsidiaries, or Southwestern Energy. Southwestern Energy accounted for 15.9% of our revenue for the year ended December 31, 2011 and 14.3% of our revenues for the nine months ended September 30, 2012. Our ten largest customers accounted for 53% and 54% of our revenues for the year ended December 31, 2011 and for the nine months ended September 30, 2012, respectively. The loss of all or even a portion of the compression services we provide to our key customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

The erosion of the financial condition of our customers could adversely affect our business.

During times when the natural gas or oil markets weaken, our customers are more likely to experience financial difficulties and the lack of availability of debt or equity financing, which could result in a reduction in our customers' spending for our services. For example, our customers could seek to preserve capital by using lower cost providers, not renewing month-to-month contracts or determining not to enter into any new compression service contracts. Reduced demand for our services could adversely affect our business, results of operations, financial condition and cash flows. In addition, in the event of the financial failure of a customer, we could experience a loss of all or a portion of our outstanding accounts receivable associated with that customer.

We face significant competition that may cause us to lose market share and reduce our ability to make distributions to our unitholders.

The compression business is highly competitive. Some of our competitors have a broader geographic scope, as well as greater financial and other resources than we do. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flows could be adversely affected by the activities of our competitors and our customers. If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to compete effectively. Some of these competitors may expand or construct newer, more powerful or more flexible compression fleets that would create additional competition for us. Additionally, there are lower barriers to entry for customers as competitors seeking to purchase individual compression units. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and reduce our ability to make cash distributions to our unitholders.

Our customers may choose to vertically integrate their operations by purchasing and operating their own compression fleet, or expanding the amount of compression units they currently own.

Our customers that are significant producers, processors, gatherers and transporters of natural gas and crude oil may choose to vertically integrate their operations by purchasing and operating their own compression fleets in lieu of using our compression services. Currently, the availability of attractive financing terms from financial institutions and equipment manufacturers facilitates this possibility by making the purchase of individual compression units increasingly affordable to our customers. Such vertical integration or increases in vertical integration could result in decreased demand for our compression services, which may have a material adverse effect on our business, results of operations, financial condition and reduce our ability to make cash distributions to our unitholders.

A significant portion of our services are provided to customers on a month-to-month basis, and we cannot be sure that our customers will continue to contract for these services that have continued beyond the primary term.

As of September 30, 2012, approximately 33% of our compression services on a horsepower basis (and 40% on a revenue basis for the nine months ended September 30, 2012) were provided on a month-to-month basis to customers who continue to utilize our services following expiration of the primary term of their contracts with us. These customers can generally terminate their month-to-month compression services contracts on 30-days' written notice. If a significant number of these customers were to terminate their month-to-month services, or attempt to renegotiate their month-to-month contracts at substantially lower rates, it could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

We may be unable to grow our cash flows if we are unable to expand our business, which could limit our ability to increase distributions to our unitholders.

A principal focus of our strategy is to continue to grow the per unit distribution on our units by expanding our business. Our future growth will depend upon a number of factors, some of which we cannot control. These factors include our ability to:

- develop new business and enter into service contracts with new customers;
- retain our existing customers and maintain or expand the services we provide them;
- recruit and train qualified personnel and retain valued employees;
- expand our geographic presence;
- effectively manage our costs and expenses, including costs and expenses related to growth;
- consummate accretive acquisitions;
- obtain required debt or equity financing for our existing and new operations; and
- meet customer-specific contract requirements or pre-qualifications.

If we do not achieve our expected growth, we may not be able to achieve our estimated results and, as a result, we may not be able to pay the aggregate minimum quarterly distribution on our common units and subordinated units and the 2.0% general partner interest, in which event the market price of our common units will likely decline materially.

We may be unable to grow successfully through future acquisitions, and we may not be able to integrate effectively the businesses we may acquire, which may impact our operations and limit our ability to increase distributions to our unitholders.

From time to time, we may choose to make business acquisitions to pursue market opportunities, increase our existing capabilities and expand into new areas of operations. While we have reviewed acquisition opportunities in the past and will continue to do so in the future, we have not actively pursued any acquisitions, and in the future we may not be able to identify attractive acquisition opportunities or successfully acquire identified targets. In addition, we may not be successful in integrating any future acquisitions into our existing operations, which may result in unforeseen operational difficulties or diminished financial performance or require a disproportionate amount of our management's attention. Even if we are successful in integrating future acquisitions into our existing operations, we may not derive the benefits, such as operational or administrative synergies, that we expected from such acquisitions, which may result in the commitment of our capital resources without the expected returns on such capital. Furthermore, competition for acquisition opportunities may escalate, increasing our cost of making acquisitions or causing us to refrain from making acquisitions. Our inability to make acquisitions, or to integrate successfully future acquisitions into our existing operations, may adversely impact our operations and limit our ability to increase distributions to our unitholders.

Our ability to grow in the future is dependent on our ability to access external expansion capital.

We will distribute all of our available cash after expenses and prudent operating reserves to our unitholders. We expect that we will rely primarily upon external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities, to fund expansion capital expenditures. However, we may not be able to obtain equity or debt financing on terms favorable to us, or at all. To the extent we are unable to efficiently finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with other expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of borrowings or other debt by us to finance our growth strategy would result in interest expense, which in turn would affect the available cash that we have to distribute to our unitholders.

Our ability to manage and grow our business effectively may be adversely affected if we lose management or operational personnel.

We depend on the continuing efforts of our executive officers. The departure of any of our executive officers, and in particular, Eric D. Long, President and Chief Executive Officer of our general partner, could have a significant negative effect on our business, operating results, financial condition and on our ability to compete effectively in the marketplace.

Additionally, our ability to hire, train and retain qualified personnel will continue to be important and will become more challenging as we grow and if energy industry market conditions continue to be positive. When general industry conditions are good, the competition for experienced operational and field technicians increases as other energy and manufacturing companies' needs for the same personnel increases. Our ability to grow or even to continue our current level of service to our current customers will be adversely impacted if we are unable to successfully hire, train and retain these important personnel.

We depend on a limited number of suppliers and are vulnerable to product shortages and price increases, which could have a negative impact on our results of operations.

The substantial majority of the components for our natural gas compression equipment are supplied by Caterpillar (for engines), Air-X-Changers and Air Cooled Exchangers (for coolers), and Ariel Corporation (for compressor frames and cylinders). Our reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. We also rely primarily on two vendors, A G Equipment Company and Standard Equipment Corp., to package and assemble our compression units. We do not have long-term contracts with these suppliers or packagers, and a partial or complete loss of any of these sources could have a negative impact on our results of operations and could damage our customer relationships. Some of these suppliers manufacture the components we purchase in a single facility, and any damage to that facility could lead to significant delays in delivery of completed units. In addition, since we expect any increase in component prices for compression equipment or packaging costs will be passed on to us, a significant increase in their pricing could have a negative impact on our results of operations.

We are subject to substantial environmental regulation, and changes in these regulations could increase our costs or liabilities.

We are subject to stringent and complex federal, state and local laws and regulations, including laws and regulations regarding the discharge of materials into the environment, emission controls and other environmental protection and occupational health and safety concerns. Environmental laws and regulations may, in certain circumstances, impose strict liability for environmental contamination, which may render us liable for remediation costs, natural resource damages and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior owners or operators or other third parties. In addition, where contamination may be present, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage and recovery of response costs. Remediation costs and other damages arising as a result of environmental laws and regulations, and costs associated with new information, changes in existing environmental laws and regulations or the adoption of new environmental laws and regulations could be substantial and could negatively impact our financial condition or results of operations. Moreover, failure to comply with these environmental laws and regulations may result in the imposition of administrative, civil and criminal penalties and the issuance of injunctions delaying or prohibiting operations.

We conduct operations in a wide variety of locations across the continental U.S. These operations require U.S. federal, state or local environmental permits or other authorizations. We may need to apply for or amend facility permits or licenses from time to time with respect to storm water discharges, waste handling, or air emissions relating to equipment operations, which subject us to new or revised permitting conditions that may be onerous or costly to comply with. Additionally, the operation of compression units may require individual air permits or general authorizations to operate under various air regulatory programs established by rule or regulation. These permits and authorizations frequently contain numerous compliance requirements, including monitoring and reporting obligations and operational restrictions, such as emission limits. Given the wide variety of locations in which we operate, and the numerous environmental permits and other authorizations that are applicable to our operations, we may occasionally identify or be notified of technical violations of certain requirements existing in various permits or other authorizations. We could be subject to penalties for any noncompliance in the future.

We routinely deal with natural gas, oil and other petroleum products. Hydrocarbons or other hazardous substances or wastes may have been disposed or released on, under or from properties used by us to provide compression services or inactive compression unit storage or on or under other locations where such substances or wastes have been taken for disposal. These properties may be subject to investigatory, remediation and monitoring requirements under federal, state and local environmental laws and regulations.

The modification or interpretation of existing environmental laws or regulations, the more vigorous enforcement of existing environmental laws or regulations, or the adoption of new environmental laws or regulations may also negatively impact oil and natural gas exploration and production, gathering and pipeline companies, including our customers, which in turn could have a negative impact on us.

New regulations, proposed regulations and proposed modifications to existing regulations under the Clean Air Act, or CAA, if implemented, could result in increased compliance costs.

On August 20, 2010, the U.S. Environmental Protection Agency, or the EPA, published new regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocating internal combustion engines. On May 22, 2012, the EPA proposed amendments to the final rule in response to several petitions for reconsideration. The EPA must finalize the proposed amendments by January 14, 2013. All engines subject to these regulations are required to comply by October 2013. The rule will require us to undertake certain expenditures and activities, including

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purchasing and installing emissions control equipment on a portion of our engines located at major sources of hazardous air pollutants, following prescribed maintenance practices for engines (which are consistent with our existing practices), and implementing additional emissions testing and monitoring. We do not believe the costs associated with achieving compliance with these standards and proposed amendments by the October 2013 compliance date will be material.

On June 28, 2011, the EPA issued a final rule modifying existing regulations under the CAA that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The final rule will require us to undertake certain expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment on some of our natural gas compression fleet. Compliance with the final rule is not required until at least 2013. On May 22, 2012, the EPA proposed minor amendments which must be finalized by January 14, 2013. We are currently evaluating the impact that this final rule and proposed amendments will have on our operations.

On April 17, 2012 the EPA finalized rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants at 500 ppm. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our compressors at initial startup, or October 15, 2012, whichever is later. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, the Texas Commission on Environmental Quality, or the TCEQ, has finalized revisions to certain air permit programs that significantly increase the air permitting requirements for new and certain existing oil and gas production and gathering sites for 23 counties in the Barnett Shale production area. The final rule establishes new emissions standards for engines, which could impact the operation of specific categories of engines by requiring the use of alternative engines, compression packages or the installation of aftermarket emissions control equipment. The rule became effective for the Barnett Shale production area in April 2011, with the lower emissions standards becoming applicable between 2015 and 2030 depending on the type of engine and the permitting requirements. The cost to comply with the revised air permit programs is not expected to be material at this time. However, the TCEQ has stated it will consider expanding application of the new air permit program statewide. At this point, we cannot predict the cost to comply with such requirements if the geographic scope is expanded.

These new regulations and proposals, when finalized, and any other new regulations requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Climate change legislation and regulatory initiatives could result in increased compliance costs.

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases, or GHGs. In recent years, the U.S. Congress has considered legislation to reduce emissions of GHGs. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. In addition, almost half of the states have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Depending on the particular program, we could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

Independent of Congress, the EPA is beginning to adopt regulations controlling GHG emissions under its existing Clean Air Act authority. For example, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large GHG emission sources. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of GHG emissions by such regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. In 2010, the EPA also issued a final rule, known as the "Tailoring Rule," that makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. This new permitting program may affect some of our customers' largest new or modified facilities going forward. Several of the EPA's GHG rules are being challenged in court and, depending on the outcome of these proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Although it is not currently possible to predict how any such proposed or future GHG legislation or regulation by Congress, the states or multi-state regions will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business could result in increased compliance costs, additional operating restrictions or reduced demand for our services, and could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenue.

A portion of our customers' natural gas production is from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act, or SDWA, to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in 2014. The EPA also has recently announced that it believes hydraulic fracturing using fluids containing diesel fuel can be regulated under the SDWA notwithstanding the SDWA's general exemption for hydraulic fracturing. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. We cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce demand for our compression services, which would materially adversely affect our revenue and results of operations.

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We do not insure against all potential losses and could be seriously harmed by unexpected liabilities.

Our operations are subject to inherent risks such as equipment defects, malfunction and failures, and natural disasters that can result in uncontrollable flows of gas or well fluids, fires and explosions. These risks could expose us to substantial liability for personal injury, death, property damage, pollution and other environmental damages. Our insurance may be inadequate to cover our liabilities. Further, insurance covering the risks we face or in the amounts we desire may not be available in the future or, if available, the premiums may not be commercially justifiable. If we were to incur substantial liability and such damages were not covered by insurance or were in excess of policy limits, or if we were to incur liability at a time when we are not able to obtain liability insurance, our business, results of operations and financial condition could be adversely affected. Please read "Business Our Operations Environmental and Safety Regulations" for a description of how we are subject to federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health and environment.

Our debt levels may limit our flexibility in obtaining additional financing, pursuing other business opportunities and paying distributions.

We have a $600 million revolving credit facility that matures on October 5, 2015. In addition, we have the option to increase the amount of available borrowings under the revolving credit facility by $50 million, subject to receipt of lender commitments and satisfaction of other conditions. We would have had approximately $301.4 million outstanding under the revolving credit facility as of September 30, 2012, after giving effect to the closing of this offering and the application of the net proceeds as discussed under "Use of Proceeds."

Following this offering, our ability to incur additional debt will be subject to limitations in our revolving credit facility. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- we will need a portion of our cash flow to make payments on our indebtedness, reducing the funds that would otherwise be available for operation, future business opportunities and distributions; and

- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. In addition, our ability to service our debt under the revolving credit facility will depend on market interest rates, since we anticipate that the interest rates applicable to our borrowings will fluctuate with movements in interest rate markets. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may be unable to effect any of these actions on satisfactory terms, or at all.

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Restrictions in our revolving credit facility may limit our ability to make distributions to our unitholders and may limit our ability to capitalize on acquisition and other business opportunities.

The operating and financial restrictions and covenants in our revolving credit facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. Our amended and restated credit agreement, which will become effective upon the closing of this offering, restricts or limits our ability to:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- subject to exceptions, enter into transactions with affiliates;
- sell our assets; and
- acquire additional assets.

Furthermore, our revolving credit facility contains certain operating and financial covenants. Our ability to comply with the covenants and restrictions contained in the revolving credit facility may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our revolving credit facility, a significant portion of our indebtedness may become immediately due and payable, our lenders' commitment to make further loans to us may terminate, and we will be prohibited from making distributions to our unitholders. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Any subsequent replacement of our revolving credit facility or any new indebtedness could have similar or greater restrictions. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Description of Revolving Credit Facility."

An impairment of goodwill or other intangible assets could reduce our earnings.

We have recorded approximately $157.1 million of goodwill and $82.3 million of other intangible assets as of September 30, 2012. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Any event that causes a reduction in demand for our services could result in a reduction of our estimates of future cash flows and growth rates in our business. These events could cause us to record impairments of goodwill or other intangible assets. If we determine that any of our goodwill or other intangible assets are impaired, we will be required to take an immediate charge to earnings with a corresponding reduction of partners' capital resulting in an increase in balance sheet leverage as measured by debt to total capitalization. There was no impairment recorded for goodwill or other intangible assets for the year ended December 31, 2011 or during the nine months ended September 30, 2012.

Terrorist attacks, the threat of terrorist attacks, hostilities in the Middle East, or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the magnitude of the threat of future terrorist attacks on the energy industry in general and on us in particular are not known at this time. Uncertainty surrounding hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of natural gas supplies and markets for natural gas and natural gas liquids and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

Prior to this offering, we have not been required to file reports with the SEC. Upon the completion of this offering, we will become subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, or Section 404. For example, Section 404(a) will require us, among other things, to review and report annually on the effectiveness of our internal control over financial reporting. We must comply with Section 404(a) for our fiscal year ending December 31, 2013. In addition, our independent registered public accountants will be required to assess the effectiveness of an internal control over financial reporting at the end of the fiscal year after we are no longer an "emerging growth company" under the Jumpstart Our Business Startups Act, which may be for up to five fiscal years after the completion of this offering. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm's, conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

Risks Inherent in an Investment in Us

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. USA Compression Holdings is the sole member of our general partner and will have the right to appoint our general partner's entire board of directors, including its independent directors. If the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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USA Compression Holdings owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including USA Compression Holdings, have conflicts of interest with us and limited fiduciary duties and they may favor their own interests to the detriment of us and our common unitholders.

Following this offering, USA Compression Holdings, which is principally owned and controlled by Riverstone, will own and control our general partner and will appoint all of the officers and directors of our general partner, some of whom will also be officers and directors of USA Compression Holdings. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owners. Conflicts of interest will arise between USA Compression Holdings, Riverstone and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of USA Compression Holdings and the other owners of USA Compression Holdings over our interests and the interests of our common unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires USA Compression Holdings to pursue a business strategy that favors us;
- our general partner is allowed to take into account the interests of parties other than us, such as USA Compression Holdings, in resolving conflicts of interest;
- our partnership agreement limits the liability of and reduces the fiduciary duties owed by our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership interests and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the ability of the subordinated units to convert to common units;
- our general partner determines which costs incurred by it are reimbursable by us;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our partnership agreement permits us to classify up to $36.6 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

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- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our general partner controls the enforcement of the obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Please read "Conflicts of Interest and Fiduciary Duties."

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common and subordinated units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our

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partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above. Please read "Conflicts of Interest and Fiduciary Duties Fiduciary Duties."

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without USA Compression Holdings' consent.

The unitholders initially will be unable to remove our general partner because our general partner and its affiliates will own sufficient units upon completion of this offering to be able to prevent its removal. The vote of the holders of at least $66^{2}/_{3}$% of all outstanding common and subordinated units voting together as a single class is required to remove our general partner. Following the closing of this offering, USA Compression Holdings will own an aggregate of 62.2% of our outstanding common and subordinated units (or 58.8% if the underwriters' option to purchase additional common units is exercised in full). Also, if our general partner is removed without cause during the subordination period and no units held by the holders of the subordinated units or their affiliates (including the general partner and its affiliates) are voted in favor of that removal, all subordinated units will automatically be converted into common units. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

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provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith, meaning that it believed that the decisions were in the best interest of our partnership;

provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

(a) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

(b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

(c) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(d) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will conclusively be deemed that, in making its decision, the board of directors acted in good faith.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts committee of its board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and to maintain its general partner interest. The number of common units to be issued to our general partner will equal the number of common units which would have entitled the holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Our general partner's general partner interest in us (currently 2.0%) will be maintained at the

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percentage that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner's Right to Reset Incentive Distribution Levels."

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their direct transferees and their indirect transferees approved by our general partner (which approval may be granted in its sole discretion) and persons who acquired such units with the prior approval of our general partner, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of USA Compression Holdings to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

You will experience immediate and substantial dilution in pro forma net tangible book value of $8.44 per common unit.

The initial public offering price of $18.00 per common unit exceeds our pro forma net tangible book value of $9.56 per common unit as of September 30, 2012. Based on the initial public offering price of $18.00 per common unit, you will incur immediate and substantial dilution of $8.44 per common unit. This dilution results primarily because the assets contributed by our general partner and its affiliates are recorded in accordance with GAAP at their historical cost, and not their fair value. Please read "Dilution."

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units, including pursuant to our planned DRIP, or other equity securities of equal or senior rank, will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units during the subordination period, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

USA Compression Holdings may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

After the sale of the common units offered by this prospectus, USA Compression Holdings will hold an aggregate of 4,048,588 common units and 14,048,588 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. In addition, USA Compression Holdings may acquire additional common units in connection with our planned DRIP. We have agreed to provide USA Compression Holdings with certain registration rights for any common and subordinated units it owns. Please read "The Partnership Agreement Registration Rights." The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price. You may also incur a tax liability upon a sale of your units. At the completion of this offering, and assuming no exercise of the underwriters' option to purchase additional common units, USA Compression Holdings will own an aggregate of approximately 26.9% of our outstanding common units. At the end of the subordination period (which could occur as early as December 31, 2013), assuming no additional issuances of common units (other than upon the conversion of the subordinated units), USA Compression Holdings will own an aggregate of approximately 62.2% of our outstanding common units. For additional information about this right, please read "The Partnership Agreement Limited Call Right."

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Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

For a discussion of the implications of the limitations of liability on a unitholder, please read "The Partnership Agreement Limited Liability."

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, or the Delaware Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and you could lose all or part of your investment.

Prior to this offering, there has been no public market for our common units. After this offering, there will be only 11,000,000 publicly traded common units, or 12,650,000 publicly traded common units if the underwriters' option to purchase additional common units is exercised in full. In addition, USA Compression Holdings will own an aggregate of 4,048,588 common and 14,048,588 subordinated units, representing an aggregate 61.0% limited partner interest in us (or 4,015,588 common and 14,048,588 subordinated units, representing an aggregate 57.6% limited partner interest in us if the underwriters' option to purchase additional common units is exercised in full). We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The initial public offering price for the common units was determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the

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common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units after this offering or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Our common units have been approved for listing (subject to official notice of issuance) on the NYSE. Because we will be a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to investors in certain corporations that are subject to all of the NYSE corporate governance requirements. Please read "Management of USA Compression Partners, LP."

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses. In addition, the Sarbanes-Oxley Act of 2002 and related rules subsequently implemented by the SEC and the NYSE have required changes in the corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of being a publicly traded partnership, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly traded partnership reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and result in our general partner possibly having to accept reduced policy limits and coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers. We have included $3.1 million of estimated incremental costs per year associated with being a publicly traded partnership in our financial forecast included elsewhere in this prospectus. However, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

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Pursuant to recently enacted federal securities laws, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for so long as we are an emerging growth company.

We will be required to disclose changes made in our internal control over financial reporting on a quarterly basis, and we will be required to assess the effectiveness of our controls annually. However, for as long as we are an "emerging growth company" under federal securities laws, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404. We could be an emerging growth company for up to five years. See "Summary Implications of Being an Emerging Growth Company." Even if we conclude that our internal control over financial reporting is effective, our independent registered public accounting firm may still decline to attest to our assessment or may issue a report that is qualified if it is not satisfied with our controls or the level at which our controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently from us.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, please read "Material Federal Income Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are or will be so treated, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, there would be a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax each year at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of any similar taxes by any other state may substantially reduce the cash available for distribution to our

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unitholders and, therefore, negatively impact the value of an investment in our common units. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to additional amounts of entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, judicial interpretations of the U.S. federal income tax laws may have a direct or indirect impact on our status as a partnership and, in some instances, a court's conclusions may heighten the risk of a challenge regarding our status as a partnership. Moreover, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes or differing judicial interpretations of existing laws could be applied retroactively and could negatively impact the value of an investment in our common units.

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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Tax gain or loss on the disposition of our common units could be more or less than expected.

If our unitholders sell common units, they will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale of common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale. Please read "Material Federal Income Tax Consequences Disposition of Common Units Recognition of Gain or Loss" for a further discussion of the foregoing.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read "Material Federal Income Tax Consequences Tax Consequences of Unit Ownership Section 754 Election" for a further discussion of the effect of the depreciation and amortization positions we will adopt.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We will prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. Recently, however, the U.S. Treasury

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Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Please read "Material Federal Income Tax Consequences Disposition of Common Units Allocations Between Transferors and Transferees."

A unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to effect a short sale of common units; therefore, our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month

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period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A technical termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for such tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby a publicly traded partnership that technically terminated may request publicly traded partnership technical termination relief which, if granted by the IRS, among other things would permit the partnership to provide only one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years. Please read "Material Federal Income Tax Consequences Disposition of Common Units Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We initially expect to conduct business in thirteen states. Many of these states currently impose a personal income tax on individuals. Many of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all foreign, federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

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USE OF PROCEEDS

We will receive net proceeds of approximately $180.7 million from this offering, after deducting the underwriting discounts, structuring fees and commissions and offering expenses (assuming no exercise of the underwriters' option to purchase additional common units).

We will use the net proceeds from this offering (excluding the net proceeds from any exercise of the underwriters' option to purchase additional common units) to repay $180.7 million of indebtedness outstanding under our revolving credit facility. We will incur indebtedness under our revolving credit facility to fund capital expenditures and for working capital needs. We have incurred indebtedness from time to time under our revolving credit facility to fund capital expenditures and for working capital purposes. On December 15, 2011 we used borrowings under the facility to purchase the compression units previously leased from Caterpillar for $43 million. On June 1, 2012, we amended our revolving credit facility to increase the overall commitments under the facility from $500 million to $600 million and entered into our amended and restated credit facility, which will become effective only upon the closing of this offering, to, among other things, permit the offering-related transactions. At September 30, 2012, the interest rate on amounts borrowed under the revolving credit facility was 3.0%. Affiliates of each of the underwriters participating in this offering are lenders under our revolving credit facility and will receive a substantial portion of the proceeds from this offering pursuant to the repayment of a portion of the borrowings thereunder. Please read "Underwriting FINRA Rules."

We will use the net proceeds from any exercise of the underwriters' option to purchase additional common units to repay outstanding borrowings under our revolving credit facility.

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CAPITALIZATION

The following table shows:

- our historical cash and capitalization as of September 30, 2012; and
- our historical cash and capitalization as of September 30, 2012, as adjusted to reflect this offering, the use of the net proceeds from this offering to repay $180.7 million of indebtedness outstanding under our revolving credit facility, and the conversion of our limited partner and general partner interests in connection with the closing of this offering as described under "Summary Partnership Structure and Offering-Related Transactions." See "Use of Proceeds."

This table does not reflect the issuance of up to 1,650,000 common units that may be sold to the underwriters upon exercise of their option to purchase additional common units from us, or the use of proceeds from the sale of such units to repay indebtedness outstanding under our revolving credit facility. We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	As of September 30, 2012	
	Historical	**As Adjusted**
	(in thousands)	
Cash	$ 7	$ 7
Long-term debt (including current maturities):		
Revolving credit facility(1)	$ 482,137	$ 301,409
Other notes payable	7	7
Total long-term debt	482,144	301,416
Partners' equity:		
Limited partner's capital(2)	340,192	
General partner's capital(3)	2,386	
Common unitholders		254,932
Subordinated unitholder		257,490
General partner interest		10,884
Total partners' equity	342,578	523,306
Total capitalization	$ 824,722	$ 824,722

(1) As of December 31, 2012, there was approximately $502.3 million outstanding under our revolving credit facility.

(2) We will convert the limited partner interest held by USA Compression Holdings into common units and subordinated units, representing an aggregate 61.0% limited partner interest in us.

(3) We will convert the general partner interest held by USA Compression GP, LLC, our general partner, into a 2.0% general partner interest in us and our incentive distribution rights.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the pro forma net tangible book value per unit after the offering. On a pro forma basis as of September 30, 2012, after giving effect to the offering of common units and the application of the related net proceeds, and assuming the underwriters' option to purchase additional common units is not exercised, our net tangible book value was $283.9 million, or $9.56 per unit. Purchasers of common units in this offering will experience substantial and immediate dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Initial public offering price per common unit		$ 18.00
Net tangible book value per unit before the offering(1)	$ 5.52	
Increase in net tangible book value per unit attributable to purchasers in the offering	4.04	
Less: Pro forma net tangible book value per unit after the offering(2)(3)		$ 9.56
Immediate dilution in net tangible book value per common unit to new investors(3)		$ 8.44

(1) Determined by dividing the net tangible book value (total tangible assets less total liabilities) of the contributed interests by the number of units (4,048,588 common units, 14,048,588 subordinated units and the 2.0% general partner interest) to be issued to USA Compression Holdings and its affiliates in connection with this offering.

(2) Determined by dividing our pro forma net tangible book value by the total number of units to be outstanding after the offering (15,048,588 common units, 14,048,588 subordinated units and 593,820 units representing the 2.0% general partner interest).

(3) Assumes no exercise of the underwriters' option to purchase additional common units from us. After giving effect to the full exercise of the underwriters' option to purchase 1,650,000 additional common units from us, the pro forma net tangible book value per common unit after the offering would be $312.1 million, resulting in an immediate dilution in net tangible book value to purchasers in the offering of $8.04 per common unit.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by our general partner and its affiliates and by the purchasers of common units in this offering upon consummation of the transactions contemplated by this prospectus:

	No Exercise of the Underwriters' Option to Purchase Additional Common Units				Full Exercise of the Underwriters' Option to Purchase Additional Common Units			
	Units Acquired		Total Consideration		Units Acquired		Total Consideration	
	Number	Percent	Amount	Percent	Number	Percent	Amount	Percent
General partner and affiliates(1)	18,690,996	63.0%	$ 342,578,713	63.4%	18,690,996	59.6%	$ 342,578,713	60.1%
New investors	11,000,000	37.0%	$ 198,000,000	36.6%	12,650,000	40.4%	$ 227,700,000	39.9%
Total	29,690,996	100.0%	$ 540,578,713	100.0%	31,340,996	100.0%	$ 570,278,713	100.0%

(1) The units held by our general partner and its affiliates consist of 4,048,588 common units, 14,048,588 subordinated units and the 2.0% general partner interest.

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OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with the factors and assumptions upon which our cash distribution policy is based, which are included under the heading " Assumptions and Considerations" below. In addition, please read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business. For additional information regarding our historical and pro forma operating results, you should refer to our historical financial statements and pro forma financial data, and the notes thereto, included elsewhere in this prospectus.

General

Rationale for our cash distribution policy. Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a judgment that our unitholders will be better served by our distributing rather than retaining our available cash. Generally, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.

Limitations on cash distributions and our ability to change our cash distribution policy. There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay the minimum quarterly distribution or any other distribution except as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- our cash distribution policy may be subject to restrictions on distributions under our revolving credit facility or other debt agreements entered into in the future. Our revolving credit facility contains financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Revolving Credit Facility;"

- our general partner will have the authority to establish reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our general partner in good faith will be binding on our unitholders;

- although our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by USA Compression Holdings) after the subordination period has ended. At the closing of this offering, USA Compression Holdings will own our general partner and will own an aggregate of approximately 62.2% of our outstanding common and subordinated units;

- even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement;

- under Section 17-607 of the Delaware Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets;

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we may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expense, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase. A subsidiary of our general partner is entitled to reimbursement of all direct and indirect expenses incurred on our behalf, which we expect to be approximately $27.5 million for the year ending December 31, 2013;

if and to the extent our cash available for distribution materially declines, we may elect to reduce our quarterly distribution in order to service or repay our debt or fund expansion capital expenditures; and

all available cash distributed by us on any date from any source will be treated as distributed from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus from the closing of this offering through the end of the quarter immediately preceding that distribution. We anticipate that distributions from operating surplus will generally not represent a return of capital. However, operating surplus includes certain components, including a $36.6 million cash basket, that represent non-operating sources of cash. Accordingly, it is possible that return of capital distributions could be made from operating surplus. Any cash distributed by us in excess of operating surplus will be deemed to be capital surplus under our partnership agreement. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. We do not anticipate that we will make any distributions from capital surplus.

Our ability to grow is dependent on our ability to access external expansion capital. Our partnership agreement requires us to distribute all of our available cash to our unitholders. As a result, we expect that we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. To the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

Our Minimum Quarterly Distribution

Upon completion of this offering, the board of directors of our general partner will establish a minimum quarterly distribution of $0.425 per unit per complete quarter, or $1.70 per unit per year, to be paid no later than 45 days after the end of each fiscal quarter beginning with the quarter ending March 31, 2013. This equates to an aggregate cash distribution of approximately $12.6 million per quarter, or approximately $50.5 million per year, based on the number of common and subordinated units and the 2.0% general partner interest to be outstanding immediately after the completion of this offering. Our ability to make cash distributions equal to the minimum quarterly distribution pursuant to this policy will be subject to the factors described above under the caption " General Limitations on Cash Distributions and Our Ability to Change Our Distribution Policy."

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If the underwriters' option to purchase additional common units is exercised, we will use the proceeds to repay borrowings under our revolving credit facility. Assuming the full exercise of the underwriters' option to purchase additional common units, the aggregate cash distribution will be approximately $13.3 million per quarter, or approximately $53.3 million per year.

Initially, our general partner will be entitled to 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner's initial 2.0% interest in these distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest.

The table below sets forth the number of outstanding common units (assuming no exercise and full exercise of the underwriters' option to purchase additional common units from us) and subordinated units and the general partner interest upon the closing of this offering and the aggregate distribution amounts payable on such units at our minimum quarterly distribution rate of $0.425 per unit per quarter ($1.70 per unit on an annualized basis).

	No Exercise of Underwriters' Option to Purchase Additional Common Units			Full Exercise of Underwriters' Option to Purchase Additional Common Units		
		Distributions			Distributions	
	Number of Units/GP Interest	One Quarter	Four Quarters	Number of Units/GP Interest	One Quarter	Four Quarters
Publicly held common units	11,000,000	$ 4,675,000	$ 18,700,000	12,650,000	$ 5,376,250	$ 21,505,000
Common units held by USA Compression Holdings	4,048,588	1,720,650	6,882,600	4,015,588	1,706,625	6,826,500
Subordinated units held by USA Compression Holdings	14,048,588	5,970,650	23,882,600	14,048,588	5,970,650	23,882,600
General partner interest held by USA Compression GP, LLC	593,820	252,374	1,009,494	626,820	266,398	1,065,594
Total	29,690,996	$ 12,618,674	$ 50,474,693	31,340,996	$ 13,319,923	$ 53,279,693

The subordination period generally will end if we have earned and paid at least $1.70 on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2015. If, in respect of any quarter, we have earned and paid at least $2.55 (150.0% of the annualized minimum quarterly distribution) on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner's 2.0% interest and the related distribution on the incentive distributions rights for the four-quarter period immediately preceding that date, the subordination period will terminate automatically and all of the subordinated units will convert into an equal number of common units. Please read the "Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period."

If we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units, we will use this excess available cash to pay any distribution arrearages related to prior quarters before any cash distribution is made to holders of subordinated units. Our subordinated units will not accrue arrearages for unpaid quarterly distributions or quarterly distributions less than the minimum quarterly distribution. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period."

The requirement to distribute available cash quarterly, as provided in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above. We do not anticipate that our general partner will

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establish cash reserves as of the closing of this offering or during the year ending December 31, 2013. We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 1st of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust the quarterly distribution for the period from the closing of this offering through March 31, 2013 based on the actual length of the period.

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our minimum quarterly distribution of $0.425 per unit for the four-quarter period ending December 31, 2013. In those sections, we present two tables, consisting of:

"Unaudited Pro Forma Cash Available for Distribution," in which we present the amount of cash we would have had available for distribution on a pro forma basis for the twelve months ended December 31, 2011 and September 30, 2012, derived from our unaudited pro forma financial data included in this prospectus, as adjusted to give pro forma effect to the offering and the offering-related transactions; and

"Estimated Cash Available for Distribution," in which we demonstrate our ability to generate the minimum estimated Adjusted EBITDA necessary for us to pay the minimum quarterly distribution on all units for the four-quarter period ending December 31, 2013.

Pro Forma Cash Available for Distribution for the Twelve Months Ended December 31, 2011 and September 30, 2012

If we had completed the transactions contemplated in this prospectus on January 1, 2011, our pro forma cash available for distribution for the twelve months ended December 31, 2011 and September 30, 2012 would have been approximately $33.5 million and $36.0 million, respectively. This amount would have been sufficient to pay the full minimum quarterly distribution on all of the common units for the twelve months ended December 31, 2011 and September 30, 2012, but would have been insufficient by approximately $16.9 million and $14.5 million, respectively, to pay the full minimum quarterly distribution on the subordinated units for these periods.

The pro forma financial statements, upon which pro forma cash available for distribution is based, do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. Furthermore, cash available for distribution is a cash accounting concept, while our pro forma financial statements have been prepared on an accrual basis. We derived the amounts of pro forma cash available for distribution shown above in the manner described in the table below. As a result, the amount of pro forma cash available for distribution should only be viewed as a general indication of the amount of cash available for distribution that we might have generated had we been formed in earlier periods. Please see our unaudited pro forma financial statements included elsewhere in this prospectus.

The following table illustrates, on a pro forma basis, for the twelve months ended December 31, 2011 and September 30, 2012, the amount of available cash (without any reserve) that would have been available for distribution to our unitholders, assuming that the offering had been consummated on January 1, 2011. The pro forma adjustments presented below give effect to (i) this offering and the related transactions, (ii) the entry into the second amendment to our revolving credit facility in November 2011, (iii) the entry into the third amendment to our revolving credit facility in June 2012 and (iv) the effectiveness of our amended and restated credit agreement, which we entered into in June 2012 and amended in December 2012. Pro forma Adjusted EBITDA and pro forma cash available for distribution are further adjusted to give effect to (i) the purchase on December 15, 2011 of the compression units previously leased from Caterpillar for $43 million, (ii) the termination of interest rate swaps related to our revolving credit facility in connection with the closing of this offering and (iii) the elimination of management fees and restructuring charges that we do not expect to incur in future periods. Certain of the adjustments are explained in further detail in the footnotes to such adjustments.

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Unaudited Pro Forma Cash Available for Distribution

	Twelve Months Ended(1) December 31, 2011	Twelve Months Ended(1) September 30, 2012
	(in thousands, except per unit and operating data)	
Pro forma revenues:		
Contract operations	$ 93,896	$ 110,419
Parts and service	4,824	4,989
Total pro forma revenues	98,720	115,408
Pro forma costs and expenses:		
Cost of operations, exclusive of depreciation and amortization(2)	39,605	39,476
Selling, general and administrative	12,726	17,153
Restructuring charges(3)	300	300
Depreciation and amortization	32,738	39,284
(Gain) loss on sale of assets	178	276
Total pro forma costs and expenses	85,547	96,489
Pro forma operating income	13,173	18,919
Pro forma other income (expense):		
Interest expense(4)	(6,303)	(9,619)
Other	21	27
Pro forma total other expense	(6,282)	(9,592)
Pro forma income before income tax expense	6,891	9,327
Pro forma income tax expense(5)	155	188
Pro forma net income	$ 6,736	$ 9,139
Adjustments to reconcile pro forma net income to pro forma Adjusted EBITDA(6):		
Add:		
Depreciation and amortization	32,738	39,284
Interest expense	6,303	9,619
Income tax expense	155	188
Equipment operating lease expense(7)	4,053	769
Riverstone management fee(8)	1,000	1,500
Restructuring charges	300	300
Pro forma Adjusted EBITDA	$ 51,285	$ 60,799
Adjustments to reconcile pro forma Adjusted EBITDA to pro forma cash available for distribution:		
Less:		
Cash interest expense before termination of interest rate swaps and equipment operating lease schedules(9)	7,062	10,282
Increase in cash interest expense due to the purchase of equipment and termination of the equipment operating lease schedules(10)	717	240
Income tax expense	155	188
Riverstone management fee	1,000	1,500
Expansion capital expenditures(11)	124,303	212,038
Maintenance capital expenditures(12)	8,961	12,514
Add:		
Borrowings to fund expansion capital expenditures(13)	124,303	212,038
Reduction in cash interest expense due to termination of interest rate swaps(14)	3,254	3,041
Pro forma cash available for distribution	36,644	39,116
Less: Incremental general and administrative expenses associated with being a publicly traded partnership(15)	3,100	3,100
Pro forma cash available for distribution by USA Compression Partners, LP	$ 33,544	$ 36,016

Per unit minimum annual distribution(16)		1.70		1.70
Annual distributions to:				
Publicly held common units		18,700		18,700
Common units held by USA Compression Holdings		6,883		6,883
Subordinated units held by USA Compression Holdings		23,883		23,883
General partner interest of our general partner		1,009		1,009
Total minimum annual cash distributions	$	50,475	$	50,475
Surplus / (Shortfall)		(16,931)		(14,459)

(1) Unaudited pro forma cash available for distribution for the year ended December 31, 2011 was derived from the unaudited pro forma financial statements included elsewhere in this prospectus. Unaudited pro forma cash available for distribution for the twelve months ended September 30, 2012 was derived by combining pro forma amounts for the three months ended December 31, 2011 (not included in this prospectus) and the nine months ended September 30, 2012 (included in this prospectus).

(2) Includes $4.1 million and $0.8 million for the twelve months ended December 31, 2011 and September 30, 2012, respectively, of equipment operating lease expense related to compression units leased from Caterpillar. On December 15, 2011, we purchased the compression units that were previously leased under the operating lease facility for $43 million.

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(3)

During the year ended December 31, 2011, we incurred $0.3 million of restructuring charges that were for severance and retention benefits related to the termination of certain administrative employees. These charges are reflected as restructuring charges in our consolidated statement of operations for the year ended December 31, 2011. We paid approximately $0.1 million of these restructuring charges in the three months ended March 31, 2012, and paid the remaining $0.2 million in the three months ended June 30, 2012.

(4)

On June 1, 2012 we amended our revolving credit facility to increase the overall commitments under the facility from $500 million to $600 million. Our revolving credit facility provides for an applicable margin for LIBOR loans of 200 to 275 basis points above LIBOR, depending on our leverage ratio, a reduction from 300 to 375 basis points above LIBOR prior to an earlier amendment dated November 16, 2011. Historical interest rates averaged 3.71% for the year ended December 31, 2011 and 3.0% for the nine-month period ended September 30, 2012. Pro forma interest expense is based on an average rate of 2.2% and 2.5% for the year ended December 31, 2011 and the nine-month period ended September 30, 2012, respectively.

(5)

This represents the Texas franchise tax (applicable to income apportioned to Texas beginning January 1, 2007) which, in accordance with ASC 740, is classified as an income tax for reporting purposes.

(6)

Adjusted EBITDA is defined as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees and expenses under our operating lease with Caterpillar. Please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures" for more information regarding Adjusted EBITDA.

(7)

Represents equipment operating lease expenses related to the Caterpillar equipment operating lease described in footnote (2) above. Because we purchased the compression units subject to this equipment operating lease from Caterpillar on December 15, 2011, we believe it is useful to investors to view our results excluding these payments.

(8)

Represents management fees paid to Riverstone, recorded in selling, general and administrative expense, for services performed during 2011 and the twelve months ended September 30, 2012. As these fees will not be paid by us following this offering, we believe it is useful to investors to view our results excluding these fees.

(9)

Comprised of estimated interest expense of $6.3 million for the year ended December 31, 2011, (i) increased by the $2.6 million fair value gain on the interest rate swaps and (ii) less debt issuance amortization cost of $1.9 million for the year ended December 31, 2011. Comprised of estimated interest expense of $9.6 million for the twelve months ended September 30, 2012, (i) increased by the $2.9 million fair value gain on the interest rate swaps and (ii) less debt issuance amortization cost of $2.3 million.

(10)

Reflects a net increase in cash interest expense of $0.7 million and $0.2 million for the twelve months ended December 31, 2011 and September 30, 2012, respectively, from additional borrowings under our revolving credit facility to finance the purchase of compression units leased from Caterpillar as described in footnotes (2) and (7) above.

(11)

Reflects actual expansion capital expenditures for the period presented. Expansion capital expenditures are capital expenditures made to expand the operating capacity or revenue generating capacity of existing or new assets, including by acquisition of compression units or through modification of existing compression units to change their capacity. On December 15, 2011, we purchased all the compression units previously leased from Caterpillar for $43 million, which is included in expansion capital expenditures for the twelve months ended December 30, 2011. On December 16, 2011, we entered into an agreement with one of our compression equipment suppliers to reduce certain previously made progress payments by $8 million and received a credit. We applied this $8 million credit to new compression units purchased from this supplier in the first quarter of 2012 and included the $8 million in expansion capital expenditures for the twelve months ended September 30, 2012.

(12)

Reflects actual maintenance capital expenditures for the period presented. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the operating capacity of our assets and extend their useful lives, or other capital expenditures that are incurred in maintaining our existing business and related cash flow.

(13)

Represents borrowings we made under our revolving credit facility to fund expansion capital expenditures.

(14)

Reflects a reduction in cash interest expense of $3.3 million and $3.0 million for the twelve months ended December 31, 2011 and September 30, 2012, respectively, due to the termination of out-of-the money interest rate swap agreements. We intend to terminate these interest rate swap agreements prior to the closing of this offering and, therefore, believe it is useful to investors to view our cash available for distribution excluding the impact of these swaps.

(15)

Reflects an adjustment for estimated incremental cash expenses associated with being a publicly traded partnership, including costs associated with annual and quarterly reports to unitholders, financial statement audits, tax return and Schedule K-1 preparation and distribution, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation. We estimate these incremental general and administrative expenses, some of which will be allocated to us by USA Compression Holdings, will increase our expenses by approximately $3.1 million per year.

(16) Pro forma cash distributions are based on an assumed distribution of $0.425 per unit per quarter. Our pro forma cash available for distribution for the twelve months ended December 31, 2011 and September 30, 2012 would have been sufficient to pay the full minimum quarterly distribution on the common units and 30.5% and 40.7%, respectively, of the minimum quarterly distribution on the subordinated units during this period.

Estimated Cash Available for Distribution for the Year Ending December 31, 2013

As a result of the factors described in this section and in " Assumptions and Considerations" below, we believe we will be able to pay the minimum quarterly distribution on all of our common units, subordinated units and the 2.0% general partner interest for the four-quarter period ending December 31, 2013.

In order to pay the minimum quarterly distribution of $0.425 per unit on all our common units, subordinated units and the 2.0% general partner interest for the four-quarter period ending December 31, 2013, we estimate that our Adjusted EBITDA for the year ending December 31, 2013 must be at least $82.1 million. Adjusted EBITDA should not be considered an alternative to net

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income, operating income, cash flows from operating activities or any other measure of financial performance calculated in accordance with GAAP, as those items are used to measure our operating performance, liquidity or ability to service debt obligations. Please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA.

We also anticipate that if our Adjusted EBITDA for such period is at or above our estimate, we would be permitted to make the minimum quarterly distributions on all the common units, subordinated units and the 2.0% general partner interest under the applicable covenants, if any, under our revolving credit facility.

We believe we will generate estimated Adjusted EBITDA of $82.1 million for the year ending December 31, 2013, which includes approximately $3.1 million of estimated incremental cash expense associated with being a publicly traded partnership. You should read " Assumptions and Considerations" below for a discussion of the material assumptions underlying this belief, which reflects our judgment of conditions we expect to exist and the course of action we expect to take. If our estimate is not achieved, we may not be able to pay the minimum quarterly distribution on all our units. We can give you no assurance that our assumptions will be realized or that we will generate the $82.1 million in Adjusted EBITDA required to pay the minimum quarterly distribution on all our common units, subordinated units and the 2.0% general partner interest for the four-quarter period ending December 31, 2013. There will likely be differences between our estimates and the actual results we will achieve, and those differences could be material. If we do not generate the estimated Adjusted EBITDA or if our maintenance capital expenditures or interest expense are higher than estimated, we may not be able to pay the minimum quarterly distribution on all units for the four-quarter period ending December 31, 2013.

When considering our ability to generate our estimated Adjusted EBITDA of $82.1 million, you should keep in mind the risk factors and other cautionary statements under the heading "Risk Factors" and elsewhere in this prospectus. Any of these factors or the other risks discussed in this prospectus could cause our results of operations and cash available for distribution to our unitholders to vary significantly from those set forth below.

We do not as a matter of course make public projections as to future revenues, earnings, or other results of operations. However, our management has prepared the prospective financial information set forth below to present the estimated cash available for distribution for the year ending December 31, 2013. The accompanying prospective financial information was not prepared with a view toward public disclosure or with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of our management's knowledge and belief, the expected course of action and our expected future financial performance. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

Neither our independent auditors, nor any other independent accountants, have compiled, examined, or performed any procedures with respect to the prospective financial information contained herein, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and assume no responsibility for, and disclaim any association with, the prospective financial information.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast to reflect events or circumstances after the date of this prospectus. In light of the above, the statement that we believe that we will have sufficient cash available for distribution to allow us to make the full minimum quarterly distribution on all our outstanding common units, subordinated units and the 2.0% general partner interest for the four-quarter period ending December 31, 2013 should not be regarded as a representation by us or the underwriters or any other person that we will make such distributions.

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The following table shows how we calculate the estimated Adjusted EBITDA necessary to pay the minimum quarterly distribution on all our common units, subordinated units and the 2.0% general partner interest for the four quarters ending December 31, 2013. Our estimated Adjusted EBITDA presents the forecasted results of operations of USA Compression Partners, LP for the year ending December 31, 2013. Our assumptions that we believe are relevant to particular line items in the table below are explained in the corresponding footnotes and in " Assumptions and Considerations."

Estimated Cash Available for Distribution

	Year Ending December 31, 2013 (in thousands, except per unit data)
Revenues:	
Contract operations	$ 144,120
Parts and service	1,254
Total revenues	145,374
Costs and expenses:	
Cost of operations, exclusive of depreciation and amortization(1)	44,358
Selling, general and administrative(2)	18,915
Depreciation and amortization	50,009
Total costs and expenses	113,282
Operating income	32,092
Interest expense(3)	(11,941)
Income before income tax expense	20,151
Income tax expense(4)	242
Net income	$ 19,909
Adjustments to reconcile net income to estimated Adjusted EBITDA(5):	
Add:	
Depreciation and amortization	50,009
Interest expense(3)	11,941
Income tax expense	242
Estimated Adjusted EBITDA	$ 82,101
Adjustments to reconcile estimated Adjusted EBITDA to estimated cash available for distribution:	
Less:	
Cash interest expense(3)(6)	10,477
Income tax expense	242
Expansion capital expenditures(7)	94,247
Maintenance capital expenditures(8)	15,400
Add:	
Borrowings to fund expansion capital expenditures	94,247
Estimated cash available for distribution	$ 55,982
Per unit minimum annual distribution	1.70
Annual distributions to:(9)	
Publicly held common units(3)	18,700
Common units held by USA Compression Holdings	6,883

Subordinated units held by USA Compression Holdings		23,883
General partner interest of our general partner		1,009
Total minimum annual cash distributions(3)	$	50,475
Excess of cash available for distributions over total minimum annual distributions(3)		5,508

(1) Excludes equipment operating lease expense related to compression units leased from Caterpillar. On December 15, 2011, we purchased all the compression units that were previously leased from Caterpillar for $43 million and terminated all the lease schedules and covenants under the facility. Also includes $16.8 million of estimated direct and indirect expenses for which our general partner will be entitled to reimbursement.

(2) Includes $3.1 million for estimated incremental cash expense associated with being a publicly traded partnership, including costs associated with annual and quarterly reports to unitholders, financial statement audits, tax return and Schedule K-1 preparation and distribution, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation. Also includes $10.7 million of estimated direct and indirect expenses for which our general partner will be entitled to reimbursement.

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(3) We intend to use the net proceeds, if any, from the exercise by the underwriters of their option to purchase additional units to repay borrowings under our revolving credit facility. If the underwriters exercise their option to purchase additional units in full, we estimate that estimated cash available for distribution for the year ending December 31, 2013 will increase to $56.8 million as a result of a $0.8 million decrease in interest expense and cash interest expense resulting from the repayment of borrowings under our revolving credit facility. In such case, our total minimum cash distributions would increase to approximately $53.3 million and the excess of cash available for distributions over total minimum annual distributions would equal $3.5 million.

(4) This represents the Texas franchise tax (applicable to income apportioned to Texas beginning January 1, 2007) which, in accordance with ASC 740, is classified as an income tax for reporting purposes.

(5) Adjusted EBITDA is defined as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment and share-based compensation expense. Please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures" for more information regarding Adjusted EBITDA.

(6) Estimated cash interest expense of $10.5 million is comprised of estimated interest expense of $11.9 million, which includes an adjustment to give effect to this offering and the use of the net proceeds of $180.7 million, less debt issuance amortization cost of $1.4 million.

(7) Reflects estimated expansion capital expenditures. Expansion capital expenditures are capital expenditures made to expand the operating capacity or revenue generating capacity of existing or new assets, including by acquisition of compression units or through modification of existing compression units to change their capacity.

(8) Reflects estimated maintenance capital expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the operating capacity of our assets and extend their useful lives, or other capital expenditures that are incurred in maintaining our existing business and related cash flow.

(9) For information regarding the number of units outstanding after this offering, as well as assumptions relating to common units to be issued pursuant to the distribution reinvestment plan that we intend to institute following the completion of this offering, please see " Units Outstanding" below.

Assumptions and Considerations

Based on a number of specific assumptions, we believe that, following completion of this offering, we will have sufficient cash available for distribution to allow us to make the full minimum quarterly distribution on all our outstanding common units, subordinated units and the 2.0% general partner interest for the four-quarter period ending December 31, 2013. We believe that our assumptions, which include the following, are reasonable:

Contract operations revenue. We estimate that our contract operations revenue will be $144.1 million for the year ending December 31, 2013, as compared to $110.4 million for the twelve months ended September 30, 2012 on a pro forma basis. The anticipated increase in our revenue is based upon the following assumptions:

- we expect to add significant new compression unit horsepower from September 30, 2012 through December 31, 2013, substantially all of which will be comprised of units greater than 1,000 horsepower, as we believe we will have strong demand for compression services in shale plays in the U.S.;

- our estimated revenue generating horsepower is based upon (i) customer commitments representing approximately 38% of the 159,373 increase in revenue generating horsepower from September 30, 2012 to December 31, 2013, (ii) customer indications of horsepower needs related to their shorter-term field development drilling commitments and processing and transportation requirements and (iii) general discussions with our customers regarding their longer-term planned field development and enhancement programs; and

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the actual amount of revenue generating horsepower as of September 30, 2012, and the estimated amount of revenue generating horsepower for each quarter in the year ending December 31, 2013, is as follows:

	Actual	Estimated				
	September 30, 2012	December 31, 2012	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
Revenue generating horsepower	786,750	799,748	827,720	869,106	925,545	946,123
Increase in revenue generating horsepower		12,998	27,972	41,386	56,439	20,578
Percentage increase		1.7%	3.5%	5.0%	6.5%	2.2%

for the year ending December 31, 2013, the estimated service fee revenue assumes an average monthly revenue per revenue generating horsepower of $13.73 compared to $13.46 for the twelve months ended September 30, 2012 and revenue generating horsepower of 946,123 at December 31, 2013 compared to 786,750 at September 30, 2012.

the increase of our average monthly service fee per revenue generating horsepower for the twelve months ended December 31, 2013 results from the fact that market rates in 2009 and early 2010 were lower than more recent market rates, and that as older contracts at lower rates expire, a larger percentage of our contracts will be at the higher rates prevalent since early 2010. Rates improved in the second half of 2010 and remained relatively stable through 2011. We experienced some pricing pressure in 2012 across the horsepower ranges of our fleet (other than our largest horsepower units). Lower average monthly revenue per revenue generating horsepower in 2012 also resulted, in part, from the increase in the average horsepower per revenue generating compression unit, which was 692 for the year ending December 31, 2011 as compared to 768 for the twelve months ended September 30, 2012. Based on recent market trends, we believe that in 2013 we will experience improved pricing relative to the rates achieved in 2009 and early 2010.

we intend to grow the number of large-horsepower units in our fleet. While large-horsepower units in general generate better gross operating margin than lower-horsepower units, they also generate lower average revenue per revenue generating horsepower. If we continue to grow the number of large-horsepower units and deploy those units to provide services to our larger customers via multi-unit orders, our average revenue per revenue generating horsepower rates for the entire fleet will slightly decline while revenue generating horsepower increases.

our average monthly service fee per revenue generating horsepower is calculated by averaging the service fee per revenue generating horsepower for each of the months in the applicable period. For the quarters ended December 31, 2011, March 31, 2012, June 30, 2012 and September 30, 2012, our pro forma average monthly service fee per revenue generating horsepower was $13.67, $13.45, $13.38 and $13.33, respectively;

the increase in contract operations revenue of $33.7 million for the year ending December 31, 2013 as compared to the twelve months ended September 30, 2012 is primarily attributable to the increase in revenue generating horsepower and our expectation that improved pricing will ultimately improve our average monthly revenue per revenue generating horsepower as contracts that we entered into in 2009 and early 2010 expire and we enter into new contracts at higher rates; and

parts and services revenue represents repair services that are performed on compressor units owned by our customers and other third parties. Our estimate for parts and service revenue is consistent with our historical experience. We do not anticipate any significant increases in these revenues.

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Cost of operations, exclusive of depreciation and amortization. We estimate that our cost of operations will be $44.4 million for the year ending December 31, 2013, as compared to $39.5 million for the twelve months ended September 30, 2012 on a pro forma basis, which includes $0.8 million of equipment operating lease expense. The anticipated increase in our cost of operations is based upon the following assumptions:

- we estimate that the average monthly cost of operations per revenue generating horsepower will be $4.23 for the year ending December 31, 2013 as compared to $4.55 for the twelve months ended September 30, 2012 (excluding, for purposes of this comparison, $0.8 million of equipment operating lease expense). This decrease is primarily due to recognizing economies of scale from the addition of large-horsepower units, partially offset by estimates of cost escalations including the effect of inflation, higher labor rates, increases in labor costs due to the hiring and training of new field technicians and increases in lubrication costs. Our average monthly cost of operations per revenue generating horsepower is calculated by averaging the monthly cost of operations per revenue generating horsepower for each of the months in the applicable period.

Selling, general and administrative expense. We estimate that selling, general and administrative expense will be $18.9 million for the year ending December 31, 2013, which includes approximately $3.1 million in expenses associated with being a publicly traded partnership, as compared to $17.2 million for the twelve months ended September 30, 2012 on a pro forma basis. As a percentage of revenue, selling, general and administrative expense is expected to decrease in the year ending December 31, 2013 (excluding the estimated $3.1 million of expenses associated with being a publicly traded partnership) as a result of the increase in revenue from period to period. Our estimate does not include any amounts for potential cash-based compensation awards pursuant to our 2013 Long-Term Incentive Plan. Any such cash-based awards would increase our selling, general and administrative expense and decrease our cash available for distribution.

Depreciation and amortization expense. We estimate that depreciation expense will be $50.0 million for the year ending December 31, 2013, as compared to $39.3 million for the twelve months ended September 30, 2012 on a pro forma basis. Depreciation expense is consistently assumed to be based on the average depreciable asset lives and depreciation methodologies, taking into account estimated capital expenditures primarily for additional new compression units as described below.

Interest expense. The anticipated increase in interest expense and cash interest expense is based upon the following assumptions:

- the balance on our revolving credit facility was approximately $482.1 million at September 30, 2012 and is expected to be approximately $369.9 million as of December 31, 2013. The $112.2 million net decrease in the loan balance between September 30, 2012 and December 31, 2013 reflects the use of $180.7 million of net proceeds from this offering and use of positive cash flow to repay amounts outstanding under our revolving credit facility offset by incremental borrowings in connection with running our business including the purchase of new compression units.

- we estimate average borrowings of approximately $344.0 million under our revolving credit facility for the year ending December 31, 2013, with an estimated average interest rate of 2.9% through December 31, 2013. An increase or decrease of 1.0% in the interest rate will result in increased or decreased, respectively, annual interest expense of $3.4 million;

- interest expense includes commitment fees for the unused portion of our revolving credit facility at an assumed rate of 0.375%;

- we have assumed that distributions on common and subordinated units held by USA Compression Holdings will be reinvested in additional common units under the DRIP that we intend to institute following the completion of this offering. We assume that proceeds from

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- the reinvested distributions will be used to reduce borrowings under our revolving credit facility, reducing interest expense by $0.9 million for the year ending December 31, 2013; and

- we assume that we will remain in compliance with the financial and other covenants in our revolving credit facility.

Cash interest expense. Cash interest expense excludes $1.4 million in non-cash amortization of debt issuance costs incurred in connection with borrowings under our revolving credit facility.

Income tax expense. Income tax expense represents Texas franchise tax calculated on the forecasted gross revenue apportioned to Texas for the year ending December 31, 2013. The tax is estimated to be approximately $242,000 for the year ending December 31, 2013, as compared to $188,000 for the twelve months ended September 30, 2012 on a pro forma basis. Our estimate of the franchise tax for the year ending December 31, 2013 is based on a tax rate of 0.7% (the maximum effective rate after allowable deductions). This tax is reflected in our financials as an income tax in accordance with ASC 740.

Capital expenditures. The anticipated decrease in capital expenditures is based upon the following assumptions:

- we estimate expansion capital expenditures will be approximately $94.2 million for the year ending December 31, 2013, compared to $212.0 million for the twelve months ended September 30, 2012. The estimated expansion capital expenditures for the year ending December 31, 2013 include $80.2 million of expenditures for the addition of 100,740 horsepower of compression units to our fleet, which we initially intend to deploy primarily in the shale plays where our customers are most active, as well as expenditures for the acquisition of additional vehicles and other ancillary assets required to support our growth.

- we estimate that maintenance capital expenditures will be approximately $15.4 million for the year ending December 31, 2013 compared to approximately $12.5 million for the twelve months ended September 30, 2012. Our maintenance capital expenditures are estimated based on the anticipated overhaul requirements of our compression units.

Units Outstanding. Following the completion of this offering, the public will own 11,000,000 common units, representing a 37.0% limited partner interest in us, and USA Compression Holdings will own 4,048,588 common units and 14,048,588 subordinated units, representing an aggregate 61.0% limited partner interest in us. Additionally, our general partner, USA Compression GP, LLC, will own a 2.0% general partner interest in us, and all of our incentive distribution rights. Following completion of this offering, we intend to institute a distribution reinvestment plan, or a DRIP, pursuant to which owners of common and subordinated units can reinvest their distributions in additional common units. We have been informed by USA Compression Holdings that they intend to reinvest their distributions in additional common units for the foreseeable future, and we expect USA Compression GP, LLC will utilize its distributions to make capital contributions to maintain its 2.0% general partner interest in us. We have assumed that 1,688,855 additional common units are issued as a result of the DRIP for the year ending December 31, 2013 at an assumed price of $18.00 per common unit related to the common and subordinated units that will be held by USA Compression Holdings. We cannot predict the level of participation in the DRIP by holders of our common units other than USA Compression Holdings, and therefore have assumed no additional common units will be issued to them pursuant to the DRIP. The issuance of additional common units as a result of the reinvestment of distributions by USA Compression Holdings under the DRIP will reduce our forecasted cash available for distribution on a per unit basis.

While we believe that our assumptions supporting our estimated Adjusted EBITDA and cash available for distribution for the year ending December 31, 2013 are reasonable in light of management's current beliefs concerning future events, the assumptions are inherently uncertain and are subject to significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate. If our assumptions are not realized, the actual Adjusted EBITDA and cash available for distribution that we generate could be substantially less than that currently expected and could, therefore, be insufficient to permit us to make the full minimum quarterly distribution on all of our units for the four-quarter period ending December 31, 2013, in which event the market price of the common units may decline materially.

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PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending March 31, 2013, we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the minimum quarterly distribution for the period from the closing of the offering through March 31, 2013.

Definition of available cash. Available cash, for any quarter, consists of all cash on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, our revolving credit facility or other agreements; and
  - provide funds for distributions to our unitholders for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for subordinated units unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages for the next four quarters);
- *plus*, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

Working capital borrowings are borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Intent to distribute the minimum quarterly distribution. We intend to distribute to the holders of common and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.425 per unit, or $1.70 on an annualized basis, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

General partner interest and incentive distribution rights. Initially, our general partner will be entitled to 2.0% of all quarterly distributions that we make after inception and prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our general partner's initial 2.0% interest in our distributions may be reduced if we issue additional limited partner units in the future (other than the issuance of common units upon exercise by the underwriters of their option to purchase additional common units, the issuance of common units upon conversion of outstanding subordinated units or the issuance of common units upon a reset of the incentive distribution rights) and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

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Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash we distribute from operating surplus (as defined below) in excess of $0.4888 per unit per quarter. The maximum distribution of 50.0% includes distributions paid to our general partner on its 2.0% general partner interest and assumes that our general partner maintains its general partner interest at 2.0%. The maximum distribution of 50.0% does not include any distributions that our general partner may receive on limited partner units that it owns.

Operating Surplus and Capital Surplus

General. All cash distributed will be characterized as either "operating surplus" or "capital surplus." Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating surplus. Operating surplus for any period consists of:

- $36.6 million (as described below); *plus*
- all of our cash receipts after the closing of this offering, excluding cash from interim capital transactions, which include the following:
  - borrowings (including sales of debt securities) that are not working capital borrowings;
  - sales of equity interests;
  - sales or other dispositions of assets outside the ordinary course of business; and
  - capital contributions received;

  provided that cash receipts from the termination of a commodity hedge or interest rate hedge prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the remaining scheduled life of such commodity hedge or interest rate hedge; *plus*
- working capital borrowings made after the end of the period but on or before the date of determination of operating surplus for the period; *plus*
- cash distributions paid on equity issued (including incremental distributions on incentive distribution rights) to finance all or a portion of the construction, acquisition or improvement of a capital improvement (such as equipment or facilities) in respect of the period beginning on the date that we enter into a binding obligation to commence the construction, acquisition or improvement of a capital improvement and ending on the earlier to occur of the date the capital improvement or capital asset commences commercial service and the date that it is abandoned or disposed of; *plus*
- cash distributions paid on equity issued (including incremental distributions on incentive distribution rights) to pay the construction period interest on debt incurred, or to pay construction period distributions on equity issued, to finance the capital improvements referred to above; *less*
- all of our operating expenditures (as defined below) after the closing of this offering; *less*

the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*

all working capital borrowings not repaid within twelve months after having been incurred; *less*

any loss realized on disposition of an investment capital expenditure.

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As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders and is not limited to cash generated by our operations. For example, it includes a basket of $36.6 million that will enable us, if we choose, to distribute as operating surplus cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity interests in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash that we receive from non-operating sources.

The proceeds of working capital borrowings increase operating surplus and repayments of working capital borrowings are generally operating expenditures, as described below, and thus reduce operating surplus when made. However, if a working capital borrowing is not repaid during the twelve-month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will be excluded from operating expenditures because operating surplus will have been previously reduced by the deemed repayment.

We define operating expenditures in the partnership agreement, and it generally means all of our cash expenditures, including, but not limited to, taxes, reimbursement of expenses to our general partner and its affiliates, payments made under interest rate hedge agreements or commodity hedge contracts (provided that (i) with respect to amounts paid in connection with the initial purchase of an interest rate hedge contract or a commodity hedge contract, such amounts will be amortized over the life of the applicable interest rate hedge contract or commodity hedge contract and (ii) payments made in connection with the termination of any interest rate hedge contract or commodity hedge contract prior to the expiration of its stipulated settlement or termination date will be included in operating expenditures in equal quarterly installments over the remaining scheduled life of such interest rate hedge contract or commodity hedge contract), officer compensation, repayment of working capital borrowings, debt service payments and maintenance capital expenditures, provided that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the penultimate bullet point of the definition of operating surplus above when such repayment actually occurs;
- payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;
- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions;
- distributions to our partners (including distributions in respect of our incentive distribution rights); or
- repurchases of equity interests except to fund obligations under employee benefit plans.

Capital surplus. Capital surplus is defined in our partnership agreement as any distribution of available cash in excess of our cumulative operating surplus. Accordingly, capital surplus would generally be generated by:

- borrowings other than working capital borrowings;

- sales of our equity and debt securities; and

- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets sold in the ordinary course of business or as part of normal retirement or replacement of assets.

Characterization of cash distributions. Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus from the closing of this offering through the end of the quarter immediately preceding that distribution. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Capital Expenditures

Maintenance capital expenditures are those capital expenditures required to maintain our long-term operating capacity and/or operating income. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity or operating income over the long term. Expansion capital expenditures will also include interest (and related fees) on debt incurred to finance all or any portion of the construction of such capital improvement in respect of the period that commences when we enter into a binding obligation to commence construction of a capital improvement and ending on the earlier to occur of the date any such capital improvement commences commercial service and the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of facilities that are in excess of the maintenance of our existing operating capacity or operating income, but which are not expected to expand, for more than the short term, our operating capacity or operating income.

As described above, neither investment capital expenditures nor expansion capital expenditures will be included in operating expenditures, and thus will not reduce operating surplus. Because expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of the construction or improvement of a capital asset (such as gathering compressors) in respect of the period that begins when we enter into a binding obligation to commence construction of the capital asset and ending on the earlier to occur of the date the capital asset commences commercial service or the date that it is abandoned or disposed of, such interest payments are also not subtracted from operating surplus. Losses on disposition of an investment capital expenditure will reduce operating surplus when realized and cash receipts from an investment capital expenditure will be treated as a cash receipt for purposes of calculating operating surplus only to the extent the cash receipt is a return on principal.

Capital expenditures that are made in part for maintenance capital purposes, investment capital purposes and/or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our general partner.

Subordination Period

General. Our partnership agreement provides that, during the subordination period (which we describe below), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.425 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Subordination period. Except as described below, the subordination period will begin on the closing date of this offering and expire on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ending December 31, 2015, if each of the following has occurred:

- distributions of available cash from operating surplus on each of the outstanding common and subordinated units and the related distribution on the general partner interest equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the "adjusted operating surplus" (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distribution on all of the outstanding common and subordinated units during those periods on a fully diluted weighted average basis and the related distribution on the general partner interest; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early termination of subordination period. Notwithstanding the foregoing, the subordination period will automatically terminate on the first business day after the distribution to unitholders in respect of any quarter, if each of the following has occurred:

- distributions of available cash from operating surplus on each of the outstanding common and subordinated units and the related distribution on the general partner interest equaled or exceeded $2.55 (150.0% of the annualized minimum quarterly distribution) for the four-quarter period immediately preceding that date;

- the "adjusted operating surplus" (as defined below) generated during the four-quarter period immediately preceding that date equaled or exceeded the sum of $2.55 (150.0% of the annualized minimum quarterly distribution) on all of the outstanding common and subordinated units on a fully diluted weighted average basis and the related distribution on the general partner interest and incentive distribution rights; and

- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration upon removal of the general partner. In addition, if the unitholders remove our general partner other than for cause:

- the subordinated units held by any person will immediately and automatically convert into common units on a one-for-one basis, provided (i) neither such person nor any of its affiliates voted any of its units in favor of the removal and (ii) such person is not an affiliate of the successor general partner; and

if all of the subordinated units convert pursuant to the foregoing, all cumulative common unit arrearages on the common units will be extinguished and the subordination period will end.

Expiration of the subordination period. When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will then participate pro-rata with the other common units in distributions of available cash.

Adjusted operating surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus for any period consists of:

operating surplus generated with respect to that period (excluding any amounts attributable to the items described in the first bullet point under " Operating Surplus and Capital Surplus Operating Surplus" above); *less*

any net increase in working capital borrowings with respect to that period; *less*

any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; *plus*

any net decrease in working capital borrowings with respect to that period; *plus*

any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium; *plus*

any net decrease made in subsequent periods in cash reserves for operating expenditures initially established with respect to such period to the extent such decrease results in a reduction of adjusted operating surplus in subsequent periods pursuant to the third bullet point above.

Distributions of Available Cash From Operating Surplus During the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

first, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;

second, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

third, 98.0% to the subordinated unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and *thereafter*, in the manner described in " General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity interests.

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Distributions of Available Cash From Operating Surplus After the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in " General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity interests.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner initially will be entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest if we issue additional units. Our general partner's 2.0% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future (other than the issuance of common units upon exercise by the underwriters of their option to purchase additional common units, the issuance of common units upon conversion of outstanding subordinated units or the issuance of common units upon a reset of the incentive distribution rights) and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2.0% general partner interest. Our partnership agreement does not require that the general partner fund its capital contribution with cash and our general partner may fund its capital contribution by the contribution to us of common units or other property.

Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its percentage general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that our general partner maintains its 2.0% general partner interest, that there are no arrearages on common units and that our general partner continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives a total of $0.4888 per unit for that quarter (the "first target distribution");

second, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total of $0.5313 per unit for that quarter (the "second target distribution");

third, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total of $0.6375 per unit for that quarter (the "third target distribution"); and

thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

Percentage Allocations of Available Cash From Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal percentage interest in distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total quarterly distribution per unit." The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2.0% general partner interest, assume our general partner has contributed any additional capital to maintain its 2.0% general partner interest and has not transferred its incentive distribution rights and there are no arrearages on common units.

		Marginal percentage interest in distributions	
	Total quarterly distribution per unit	**Unitholders**	**General partner**
Minimum Quarterly Distribution	$0.425	98.0%	2.0%
First Target Distribution	up to $0.4888	98.0%	2.0%
Second Target Distribution	above $0.4888 up to $0.5313	85.0%	15.0%
Third Target Distribution	above $0.5313 up to $0.6375	75.0%	25.0%
Thereafter	above $0.6375	50.0%	50.0%

General Partner's Right to Reset Incentive Distribution Levels

Our general partner, as the holder of our incentive distribution rights, or IDRs, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. Our general partner's right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the conflicts committee of our general partner, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the prior four consecutive fiscal quarters. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event are above the reset first target distribution described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution

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payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued common units based on a predetermined formula described below that takes into account the "cash parity" value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters prior to the reset event as compared to the average cash distributions per common unit during this period. Our general partner's general partner interest in us (currently 2.0%) will be maintained at the percentage immediately prior to the reset election.

The number of common units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to the quotient determined by dividing (x) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election by (y) the average of the amount of cash distributed per common unit during each of these two quarters.

Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per unit for the two fiscal quarters immediately preceding the reset election (which amount we refer to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

first, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives an amount per unit equal to 115.0% of the reset minimum quarterly distribution for that quarter;

second, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives an amount per unit equal to 125.0% of the reset minimum quarterly distribution for the quarter;

third, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives an amount per unit equal to 150.0% of the reset minimum quarterly distribution for the quarter; and

thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

The following table illustrates the percentage allocation of available cash from operating surplus between the unitholders and our general partner at various cash distribution levels (i) pursuant to the cash distribution provisions of our partnership agreement in effect at the closing of this offering, as well as (ii) following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.85.

		Marginal percentage interest in distribution		
	Quarterly distribution per unit prior to reset	**Unitholders**	**General partner**	**Quarterly distribution per unit following hypothetical reset**
Minimum Quarterly Distribution	$0.425	98.0%	2.0%	$0.85
First Target Distribution	up to $0.4888	98.0%	2.0%	up to $0.9775(1)
Second Target Distribution	above $0.4888 up to $0.5313	85.0%	15.0%	above $0.9775(1) up to $1.0625(2)
Third Target Distribution	above $0.5313 up to $0.6375	75.0%	25.0%	above $1.0625(2) up to $1.275(3)
Thereafter	above $0.6375	50.0%	50.0%	above $1.275(3)

(1)

This amount is 115.0% of the hypothetical reset minimum quarterly distribution.

(2) This amount is 125.0% of the hypothetical reset minimum quarterly distribution.

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(3) This amount is 150.0% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner, including in respect of IDRs, based on an average of the amounts distributed for a quarter for the two quarters immediately prior to the reset. The table assumes that immediately prior to the reset there would be 29,097,176 common units outstanding, our general partner has maintained its 2.0% general partner interest, and the average distribution to each common unit would be $0.85 for the two quarters prior to the reset.

				Cash distributions to general partner prior to reset			
	Quarterly distribution per unit prior to reset	**Cash distributions to common unitholders prior to reset**	**Common Units**	**2.0% general partner interest**	**Incentive distribution rights**	**Total**	**Total distributions**
Minimum Quarterly Distribution	$0.425	$ 12,366,300	$	$ 252,374	$	$ 252,374	12,618,674
First Target Distribution	up to $0.4888	1,856,400		37,886		37,886	1,894,286
Second Target Distribution	above $0.4888 up to $0.5313	1,236,630		29,097	189,132	218,229	1,454,859
Third Target Distribution	above $0.5313 up to $0.6375	3,090,120		82,403	947,637	1,030,040	4,120,160
Thereafter	above $0.6375	6,183,150		247,326	5,935,824	6,183,150	12,366,300
		$ 24,732,600	$	$ 649,086	$ 7,072,593	$ 7,721,679	$ 32,454,279

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner, including in respect of IDRs, with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there would be 37,417,873 common units outstanding, our general partner's 2.0% interest has been maintained, and the average distribution to each common unit would be $0.85. The number of common units to be issued to our general partner upon the reset was calculated by dividing (i) the average of the amounts received by our general partner in respect of its IDRs for the two quarters prior to the reset as shown in the table above, or $7,072,593, by (ii) the average available cash distributed on each common unit for the two quarters prior to the reset as shown in the table above, or $0.85.

			Cash distributions to general partner after reset				
	Quarterly distribution per unit following hypothetical reset	**Cash distributions to common unitholders following hypothetical reset**	**Common Units issued in connection with reset**	**2.0% general partner interest**	**Incentive distribution rights**	**Total**	**Total distributions**
Minimum Quarterly Distribution	$0.85	$ 24,732,600	$ 7,072,593	$ 649,086	$	$ 7,721,679	32,454,279
First Target Distribution	up to $0.9775						
Second Target Distribution	above $0.9775 up to $1.0625						
Third Target Distribution	above $1.0625 up to $1.275						
Thereafter	above $1.275						
		$ 24,732,600	$ 7,072,593	$ 649,086	$	$ 7,721,679	$ 32,454,279

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the prior four consecutive

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fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

Distributions From Capital Surplus

How distributions from capital surplus will be made. Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until the minimum quarterly distribution is reduced to zero, as described below;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

- *thereafter*, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

The preceding paragraph assumes that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

Effect of a distribution from capital surplus. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the distribution had in relation to the fair market value of the common units prior to the announcement of the distribution. Because distributions of capital surplus will reduce the minimum quarterly distribution and target distribution levels after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the minimum quarterly distribution is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

If we reduce the minimum quarterly distribution to zero, all future distributions will be made such that 50.0% will be paid to the holders of units and 50.0% to our general partner. The percentage interests shown for our general partner include its 2.0% general partner interest and assume our general partner has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the minimum quarterly distribution;

- the target distribution levels;

- the initial unit price as described below; and

- the per unit amount of any outstanding arrearages in payment of the minimum quarterly distribution.

For example, if a two-for-one split of the units should occur, the minimum quarterly distribution, the target distribution levels and the initial unit price would each be reduced to 50.0% of its initial level. If we combine our common units into a lesser number of units or subdivide our common units into a greater number of units, we will combine or subdivide our subordinated units using the same

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ratio applied to the common units. Our partnership agreement provides that we do not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if as a result of a change in law or interpretation thereof, we or any of our subsidiaries is treated as an association taxable as a corporation or is otherwise subject to additional taxation as an entity for U.S. federal, state, local or non-U.S. income or withholding tax purposes, our general partner may, in its sole discretion, reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter (after deducting our general partner's estimate of our additional aggregate liability for the quarter for such income and withholdings taxes payable by reason of such change in law or interpretation) and the denominator of which is the sum of (i) available cash for that quarter, plus (ii) our general partner's estimate of our additional aggregate liability for the quarter for such income and withholding taxes payable by reason of such change in law or interpretation thereof. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in distributions with respect to subsequent quarters.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of units to a repayment of the initial value contributed by them to us for their units, which we refer to as the "initial unit price" for each unit. The initial unit price for the common units will be the price paid for the common units issued in this offering. The allocations of gain and loss upon liquidation are also intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of adjustments for gain. The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- *first*, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until the capital account for each common unit is equal to the sum of: (i) the initial unit price; (ii) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (iii) any unpaid arrearages in payment of the minimum quarterly distribution;

- *third*, 98.0% to the subordinated unitholders, pro rata, and 2.0% to our general partner, until the capital account for each subordinated unit is equal to the sum of: (i) the initial unit price; and (ii) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

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fourth, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (i) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (ii) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98.0% to the unitholders, pro rata, and 2.0% to our general partner, for each quarter of our existence;

fifth, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (i) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (ii) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85.0% to the unitholders, pro rata, and 15.0% to our general partner for each quarter of our existence;

sixth, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (i) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (ii) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75.0% to the unitholders, pro rata, and 25.0% to our general partner for each quarter of our existence; and

thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

The percentage interests set forth above for our general partner include its 2.0% general partner interest and assume our general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common and subordinated units will disappear, so that clause (iii) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of adjustments for losses. If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to our general partner and the unitholders in the following manner:

first, 98.0% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;

second, 98.0% to the holders of common units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the common unitholders have been reduced to zero; and

thereafter, 100.0% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to capital accounts. Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the general partner's capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

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SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table presents our selected historical financial and operating data and pro forma financial data for the periods and as of the dates presented. The following table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical and pro forma financial statements and accompanying notes included elsewhere in this prospectus.

The selected historical financial and operating data has been prepared on the following basis:

- the historical financial information as of December 31, 2010 and 2011 and for the years ended December 31, 2009, 2010 and 2011 is derived from our audited financial statements, which are included elsewhere in this prospectus;

- the historical financial information as of December 31, 2007, 2008 and 2009 and for the years ended December 31, 2007 and 2008 is derived from our audited financial statements, which are not included in this prospectus;

- the historical financial information as of September 30, 2012 and for the nine months ended September 30, 2011 and September 30, 2012 is derived from our unaudited financial statements, which are included elsewhere in this prospectus; and

- the historical financial information as of September 30, 2011 is derived from our unaudited financial statements, which are not included in this prospectus.

We were acquired by USA Compression Holdings on December 23, 2010. In connection with this acquisition, our assets and liabilities were adjusted to fair value on the closing date by application of "push-down" accounting. Due to these adjustments, our unaudited condensed consolidated financial statements are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (i) the periods prior to the acquisition date for accounting purposes, using a date of convenience of December 31, 2010, are identified as "Predecessor," and (ii) the periods from December 31, 2010 forward are identified as "Successor." Please read note 1 to our audited financial statements as of December 31, 2011 included elsewhere in this prospectus.

The selected pro forma financial information for the year ended December 31, 2011 and as of and for the nine months ended September 30, 2012 is derived from our unaudited pro forma financial statements included elsewhere in this prospectus. The pro forma adjustments have been prepared as if the transactions described below had taken place on September 30, 2012, in the case of the pro forma balance sheet, or as of January 1, 2011, in the case of the pro forma statement of operations for the year ended December 31, 2011 and the nine months ended September 30, 2012. These transactions include:

- the entry into the second amendment to our revolving credit facility on November 16, 2011;

- the entry into the third amendment to our revolving credit facility on June 1, 2012 and the effectiveness of our amended and restated credit agreement, which we entered into on June 1, 2012 and amended in December 10, 2012;

- the conversion of our limited partner interests held by USA Compression Holdings into 4,048,588 of our common units and 14,048,588 of our subordinated units;

- the conversion of our general partner interest held by USA Compression GP, LLC, our general partner, into a 2.0% general partner interest in us;

- the issuance by us of all of our incentive distribution rights to USA Compression GP, LLC; and the issuance by us of 11,000,000 common units to the public in exchange for net proceeds of approximately $180.7 million, all of which will be used to repay indebtedness outstanding under our revolving credit facility.

The pro forma financial information should not be considered as indicative of the historical results we would have had or the results we will have after this offering.

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The following table includes the non-GAAP financial measure of Adjusted EBITDA. We define Adjusted EBITDA as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read " Non-GAAP Financial Measures."

	Historical							Pro Forma	
	Predecessor				Successor(1)				
	Year ended December 31,				Year Ended December 31,	Nine Months Ended September 30,	Nine Months Ended September 30,	Year Ended December 31,	Nine Months Ended September 30,
	2007	2008	2009	2010	2011	2011	2012	2011	2012
	(in thousands, except per unit and operating data)								
Revenues:									
Contract operations	$ 67,339	$ 87,905	$ 93,178	$ 89,785	$ 93,896	$ 68,762	$ 85,285	$ 93,896	$ 85,285
Parts and service	2,296	2,918	2,050	2,243	4,824	1,565	1,730	4,824	1,730
Total revenues	69,635	90,823	95,228	92,028	98,720	70,327	87,015	98,720	87,015
Costs and expenses:									
Cost of operations, exclusive of depreciation and amortization	20,513	29,320	30,096	33,292	39,605	28,057	27,928	39,605	27,928
Selling, general and administrative(2)	10,958	8,709	9,136	11,370	12,726	8,500	12,927	12,726	12,927
Restructuring charges(3)					300			300	
Depreciation and amortization	13,437	18,016	22,957	24,569	32,738	24,044	30,590	32,738	30,590
(Gain) loss of sale of assets	(3)	(235)	(74)	(90)	178	159	257	178	257
Impairment of compression equipment	1,028		1,677						
Total costs and expenses	45,933	55,810	63,792	69,141	85,547	60,760	71,702	85,547	71,702
Operating income	23,702	35,013	31,436	22,887	13,173	9,567	15,313	13,173	15,313
Other income (expense):									
Interest expense	(16,468)	(14,003)	(10,043)	(12,279)	(12,970)	(9,424)	(11,637)	(6,303)	(7,808)
Other	43	20	25	26	21	17	23	21	23
Total other expense	(16,425)	(13,983)	(10,018)	(12,253)	(12,949)	(9,407)	(11,614)	(6,282)	(7,785)
Income before income tax expense	7,277	21,030	21,418	10,634	224	160	3,699	6,891	7,528
Income tax expense(4)	155	119	190	155	155	111	144	155	144
Net income	$ 7,122	$ 20,911	$ 21,228	$ 10,479	$ 69	$ 49	$ 3,555	$ 6,736	$ 7,384

Adjusted EBITDA	$ 40,562	$ 53,274	$ 56,917	$ 51,987	$ 51,285	$ 37,162	$ 46,676	$ 51,285	$ 46,676
Pro forma net income per limited partner unit:									
Common unit									
Subordinated unit									
Other Financial Data:									
Capital expenditures(5)	$ 63,010	$ 92,708	$ 29,580	$ 18,886	$ 133,264	$ 65,153	$ 148,473		
Cash flows provided by (used in):									
Operating activities	26,441	40,699	42,945	38,572	33,782	28,673	30,375		
Investing activities	(62,642)	(88,102)	(26,763)	(18,768)	(140,444)	(64,379)	(147,121)		
Financing activities	37,591	46,364	(16,545)	(19,804)	106,662	35,706	116,749		
Operating Data (at period end, except averages) unaudited									
Fleet horsepower(6)	453,508	542,899	582,530	609,730	722,201	691,545	889,099		
Total available horsepower(7)	476,698	568,359	582,530	612,410	809,418	711,463	902,164		
Revenue generating horsepower(8)	405,807	496,606	502,177	533,692	649,285	591,290	786,750		
Average revenue generating horsepower(9)	370,826	455,673	489,243	516,703	570,900	551,566	735,639		
Revenue generating compression units	613	763	749	795	888	839	964		
Average horsepower per revenue generating compression unit(10)	665	651	655	667	692	683	784		
Horsepower utilization(11):									
At period end	93.7%	95.2%	92.0%	91.8%	95.7%	92.8%	93.4%		
Average for the period(12)	93.9%	95.9%	92.7%	92.6%	92.3%	91.4%	95.0%		

	Predecessor			Successor(1)					Pro Forma
Balance Sheet Data (at period end):									
Working capital(13)	$ (2,794)	$ (7,656)	$ (4,678)	$ (3,984)	$ (11,295)	$ (11,120)	$ (9,585)		$ (9,585)
Total assets	276,983	349,645	352,757	614,718	727,876	654,607	849,824		849,974
Long-term debt	229,861	276,537	260,470	255,491	363,773	291,544	482,137		301,559
Partners' capital	32,795	49,685	72,626	338,954	339,023	339,003	342,578		523,306

(1) Reflects the push-down of the purchase accounting for the Holdings Acquisition.

(2) Pro forma selling, general and administrative expense does not include incremental general and administrative expenses we expect to incur as a result of being a publicly traded partnership. We expect these expenses to total approximately $3.1 million per year.

(3) During the year ended December 31, 2011, we incurred $0.3 million of restructuring charges for severance and retention benefits related to the termination of certain administrative employees. These charges are reflected as restructuring charges in our consolidated statement of operations. We paid approximately $0.1 million of these restructuring charges in the three months ended March 31, 2012 and paid the remaining $0.2 million in the three months ended June 30, 2012.

(4) This represents the Texas franchise tax (applicable to income apportioned to Texas) which, in accordance with ASC 740, is classified as income tax for reporting purposes.

(5) On December 15, 2011, we purchased all the compression units previously leased from Caterpillar for $43 million and terminated all the lease schedules and covenants under the facility. This amount is included in capital expenditures for the year ended December 31, 2011. On December 16, 2011, the Partnership entered into an agreement with a compression equipment supplier to reduce certain previously made progress payments from $10 million to $2 million. The Partnership applied this $8 million credit to new compression unit purchases from this supplier in the nine months ended September 30, 2012. Before the application of this credit, capital expenditures were $156.4 million for the nine months ended September 30, 2012.

(6) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes any units on order). As of September 30, 2012, we had 31,630 of additional new compression unit horsepower on order, of which 23,135 horsepower has been delivered as of November 30, 2012 and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013.

(7) Total available horsepower is revenue generating horsepower under contract for which we are billing a customer, horsepower in our fleet that is under contract but is not yet generating revenue, horsepower not yet in our fleet that is under contract not yet generating revenue that is subject to a purchase order and idle horsepower. Total available horsepower excludes new horsepower on order for which we do not have a compression services contract.

(8) Revenue generating horsepower is horsepower under contract for which we are billing a customer.

(9) Calculated as the average of the month-end revenue generating horsepower for each of the months in the period.

(10) Calculated as the average of the month-end horsepower per revenue generating compression unit for each of the months in the period.

(11) Horsepower utilization is calculated as (i)(a) revenue generating horsepower plus (b) horsepower in our fleet that is under contract, but is not yet generating revenue plus (c) horsepower not yet in our fleet that is under contract not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Horsepower utilization based on revenue generating horsepower and fleet horsepower at each applicable period end was 89.5%, 91.5%, 86.2%, 87.5% and 89.9% for the years ended December 31, 2007, 2008, 2009, 2010 and 2011, respectively, and 85.5% and 88.5% for the nine months ended September 30, 2011 and 2012, respectively.

(12) Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period.

(13) Working capital is defined as current assets minus current liabilities.

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Non-GAAP Financial Measures

We include in this prospectus the non-GAAP financial measure of Adjusted EBITDA. We view Adjusted EBITDA as one of our primary management tools, and we track this item on a monthly basis both as an absolute amount and as a percentage of revenue compared to the prior month, year-to-date and prior year and to budget. We define Adjusted EBITDA as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. Adjusted EBITDA is used as a supplemental financial measure by our management and external users of our financial statements, such as investors and commercial banks, to assess:

- the financial performance of our assets without regard to the impact of financing methods, capital structure or historical cost basis of our assets;
- the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;
- the ability of our assets to generate cash sufficient to make debt payments and to make distributions; and
- our operating performance as compared to those of other companies in our industry without regard to the impact of financing methods and capital structure.

We believe that Adjusted EBITDA provides useful information to investors because, when viewed with our GAAP results and the accompanying reconciliations, it provides a more complete understanding of our performance than GAAP results alone. We also believe that external users of our financial statements benefit from having access to the same financial measures that management uses in evaluating the results of our business.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, our Adjusted EBITDA as presented may not be comparable to similarly titled measures of other companies.

Adjusted EBITDA does not include interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. Because we borrow money under our revolving credit facility and have historically utilized operating leases to finance our operations, interest expense and operating lease expense are necessary elements of our costs. Because we use capital assets, depreciation and impairment of compression equipment is also a necessary element of our costs. Expense related to share-based compensation expense related to equity awards to employees is also necessary to operate our business. Therefore, measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income and net cash provided by operating activities determined under GAAP, as well as Adjusted EBITDA, to evaluate our financial performance and our liquidity. Our Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities, and these measures may vary among companies. Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating this knowledge into management's decision-making processes.

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The following table reconciles Adjusted EBITDA to net income and net cash provided by operating activities, its most directly comparable GAAP financial measures, for each of the periods presented:

	Historical							Pro Forma	
	Predecessor				Successor				
	Year ended December 31,				Year Ended December 31, 2011	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Year Ended December 31, 2011	Nine Months Ended September 30, 2012
	2007	2008	2009	2010					
	(in thousands)								
Net income	$ 7,122	$ 20,911	$ 21,228	$ 10,479	$ 69	$ 49	$ 3,555	$ 6,736	$ 7,384
Interest expense	16,468	14,003	10,043	12,279	12,970	9,424	11,637	6,303	7,808
Depreciation and amortization	13,437	18,016	22,957	24,569	32,738	24,044	30,590	32,738	30,590
Income taxes	155	119	190	155	155	111	144	155	144
Impairment of compression equipment(1)	1,028		1,677						
Share-based compensation expense	2,352	225	269	382					
Equipment operating lease expense(2)			553	2,285	4,053	3,284		4,053	
Riverstone management fee(3)					1,000	250	750	1,000	750
Restructuring charges(4)					300			300	
Fees and expenses related to the Holdings Acquisition(5)				1,838					
Adjusted EBITDA	$ 40,562	$ 53,274	$ 56,917	$ 51,987	$ 51,285	$ 37,162	$ 46,676	$ 51,285	$ 46,676
Interest expense	(16,468)	(14,003)	(10,043)	(12,279)	(12,970)	(9,424)	(11,637)		
Income tax expense	(155)	(119)	(190)	(155)	(155)	(111)	(144)		
Equipment operating lease expense			(553)	(2,285)	(4,053)	(3,284)			
Riverstone management fee					(1,000)	(250)	(750)		
Restructuring charges					(300)				
Fees and expenses related to the Holdings Acquisition				(1,838)					
Other	1,666	201	288	3,362	(920)	(871)	(463)		
Changes in operating assets and liabilities:									
Accounts receivable and advance to employee	(563)	(2,458)	1,865	(336)	(976)	(142)	(1,649)		
Inventory	(216)	(155)	(3,680)	503	1,974	1,102	(950)		
Prepaids	(358)	(1,165)	608	(18)	(219)	738	864		
Other non-current assets	(2)	(3)	(4)	1	(2,601)	(2,143)	(806)		
Accounts payable	211	1,960	(857)	(825)	1,987	1,785	(6,145)		
Accrued liabilities and deferred revenue	1,764	3,167	(1,406)	455	1,730	4,111	5,379		
Net cash provided by operating activities	$ 26,441	$ 40,699	$ 42,945	$ 38,572	$ 33,782	$ 28,673	$ 30,375		

(1) Represents non-cash charges incurred to write-down long-lived assets with recorded values that are not expected to be recovered through future cash flows.

(2)

Represents expenses for the respective periods under the operating lease facility with Caterpillar, from whom we historically leased compression units and other equipment. On December 15, 2011, we purchased all the compression units that were previously leased from Caterpillar for $43 million and terminated all the lease schedules and covenants under the facility. As such, we believe it is useful to investors to view our results excluding these lease payments.

(3)

Represents management fees paid to Riverstone for services performed during 2011 and the nine months ended September 30, 2012. As these fees will not be paid by us following this offering, we believe it is useful to investors to view our results excluding these fees.

(4)

During the year ended December 31, 2011, we incurred $0.3 million of restructuring charges for severance and retention benefits related to the termination of certain administrative employees. These charges are reflected as restructuring charges in our consolidated statement of operations. We paid approximately $0.1 million of these restructuring charges in the three months ended March 31, 2012 and paid the remaining $0.2 million in the three months ended June 30, 2012. We believe that it is useful to investors to view our results excluding this non-core expense.

(5)

Represents one-time fees and expenses related to the Holdings Acquisition. These fees and expenses are not related to our operations, and we do not expect to incur similar fees or expenses in the future as a publicly traded partnership.

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

You should read the following discussion of our historical financial condition and results of operations in conjunction with the audited and unaudited financial statements and related notes and the unaudited pro forma financial statements and related notes included elsewhere in this prospectus. Among other things, those financial statements include more detailed information regarding the basis of presentation for the following information.

Overview

We are a growth-oriented Delaware limited partnership and, based on management's significant experience in the industry, we believe that we are one of the largest independent providers of compression services in the U.S. in terms of total compression unit horsepower. We have been providing compression services since 1998. We currently operate in a number of U.S. natural gas shale plays, including the Fayetteville, Marcellus, Woodford, Barnett, Eagle Ford and Haynesville shales. We believe compression services for shale production will increase in the future. According to the Annual Energy Outlook 2013 Early Release prepared by the EIA, natural gas production from shale formations will increase from 34% of total U.S. natural gas production in 2011 to 50% of total U.S. natural gas production in 2040. We also provide compression services in more mature conventional basins that will require increasing amounts of compression as they age and pressures decline.

We operate in a single business segment, the compression service business. We provide our customers with compression services to maximize their natural gas and crude oil production, throughput and cash flow. We provide domestic compression services to major oil companies and independent producers, processors, gatherers and transporters of natural gas using our modern, flexible fleet of compression units, which have been designed to be rapidly deployed and redeployed throughout the country. As part of our services, we engineer, design, operate, service and repair our compression units and maintain related support inventory and equipment.

We provide our compression services primarily under long-term, fixed fee contracts. Our contracts have initial contract terms of up to five years. Our customers generally require compression services at their locations for longer than the initial contract term. We typically continue to provide compression services to our customers beyond their initial contract terms, either through renewals or on a month-to-month basis. As of and for the nine months ended September 30, 2012, approximately 33% of our compression services on a horsepower basis (and 40% on a revenue basis) were provided to customers under contracts continuing on a month-to-month basis. Our customers are typically required to pay our monthly fee even during periods of limited or disrupted natural gas flows, which enhances the stability and predictability of our cash flows. We are not directly exposed to natural gas price risk because we do not take title to the natural gas we compress and because the natural gas used as fuel for our compression units is supplied by our customers without cost to us. Our indirect exposure to short-term volatility in natural gas and crude oil commodity prices is mitigated by the long-term nature of the majority of our contracts. As of September 30, 2012, we estimate that over 90% of our revenue generating horsepower was deployed in large-volume gathering systems, processing facilities and transportation applications.

General Trends and Outlook

From 2006 through 2008, the compression industry in the U.S. experienced a period of significant strength. Our average annual horsepower utilization rates ranged from 94% to 97% during these years, and our average revenue per revenue generating horsepower per month increased from $14.18 in 2006 to $16.24 in 2008. During 2009 and the first half of 2010, the industry experienced pricing pressure as a result of reduced commodity prices and energy activity, an excess supply of gas compression equipment in the industry and the rationalization of compression equipment by producers, processors, gatherers and transporters of natural gas that has included replacing outsourced compression services with customer-owned equipment and downsizing compression units. Average monthly revenue per revenue generating horsepower declined to $16.05 in 2009, $14.70 in 2010 and $14.07 in 2011, although our utilization rates remained high at 93% for 2009 and 2010 and 92% for 2011. Pricing for the compression industry in the U.S. began to stabilize in mid-2010 and improved slightly during the second half of 2010 and remained stable in 2011.

We anticipate that our average monthly revenue per revenue generating horsepower will continue to decline slightly through 2012, as market rates in 2009 and early 2010 were lower than market rates prior to 2009, and as older contracts at higher rates expire, a larger percentage of our contracts are at the lower rates prevalent since 2009. During 2009 and early 2010, we elected to sign shorter term contracts wherever practical to limit our long-term exposure to the lower rates prevalent at the time. Rates improved in the second half of 2010 and remained relatively stable through 2011. However, we expect to experience pricing pressure in 2012 across the horsepower ranges of our fleet (other than our largest horsepower units), with increases forecasted through 2013. Over the long term, we expect that continued improved pricing will ultimately improve our average monthly revenue per revenue generating horsepower as contracts that we entered into in 2009 and early 2010 expire and we enter into new contracts at higher rates. We intend to grow the number of large-horsepower units in our fleet. While large-horsepower units in general allow us to generate higher gross operating margins than lower-horsepower units, they also generate lower average monthly revenue per revenue generating horsepower.

Our ability to increase our revenues is dependent in large part on our ability to add new revenue generating compression units to our fleet and increase the utilization of idle compression units. During 2010, we began to see an increase in overall natural gas activity in the U.S. and experienced an increase in demand for our compression services. Our revenue generating horsepower increased approximately 33.1% as of September 30, 2012 as compared to September 30, 2011. Average revenue generating horsepower increased approximately 33.4% from the nine months ended September 30, 2011 compared to the nine months ended September 30, 2012. We believe the activity levels in the U.S. will continue to increase, particularly in shale plays. We anticipate this activity will result in higher demand for our compression services, which we believe should result in increasing revenues. However, the expected increase in overall natural gas activity and demand for our compression services may not occur for a variety of reasons. See "Forward-looking Statements."

Factors That Affect Our Future Results

Customers

We provide compression services to major oil companies and independent producers, processors, gatherers and transporters of natural gas, and operate in a number of U.S. natural gas shale plays, including the Fayetteville, Marcellus, Woodford, Barnett, Eagle Ford and Haynesville shales. Our customers use our services primarily in large-volume gathering systems, processing facilities and transportation applications. Regardless of the application for which our services are provided, our customers rely upon the availability of the equipment used to provide compression services and our expertise to help generate the maximum throughput of product, reduce fuel costs and reduce emissions. While we are currently focused on our existing service areas, our customers have natural gas compression demands in other areas of the U.S. in conjunction with their field development projects. We continually consider expansion of our areas of operation in the U.S. based upon the level of customer demand. Our modern, flexible fleet of compression units, which have been designed to be rapidly deployed and redeployed throughout the country, provides us with continuing opportunities to expand into other areas with both new and existing customers. From April 2008 through September 2012, we redeployed approximately 51,000 horsepower of our compression units from our Central operating region to our Northeast operating region, which includes the Marcellus shale, to meet increasing customer demand in that geographic area. Many of our customers have access to low-cost

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capital made available by banks and equipment manufacturers and have elected to access this capital to add compression units to their owned compression fleets. Additional purchases of compression equipment by our customers may result in reduced demand for our compression services by these customers, which could materially reduce our results of operations and ability to make cash distributions to our unitholders.

Supply and Demand for Natural Gas

We believe that as a clean alternative to other fuels, natural gas will continue to be a fuel of choice for many years to come for many industries and consumers. The EIA forecasts in its Annual Energy Outlook 2013 Early Release that natural gas consumption in the U.S. will increase by approximately 21% from 2011 to 2040. We believe this long-term increasing demand for natural gas will create increasing demand for compression services, for both natural gas fields as they age and for the development of new natural gas fields. Additionally, the shift to production of natural gas from shale, tight gas and coal bed formations that often have lower producing pressures than conventional reservoirs, results in a further increase in compression needs. In the short-term, changes in natural gas pricing, based primarily upon the supply of natural gas, will affect the development activities of natural gas producers based upon the costs associated with finding and producing natural gas in the particular natural gas and oil fields in which they are active. Although short-term declines in natural gas prices have a short-term negative effect on the development activity in natural gas fields, periods of lower development activity tend to place emphasis on improving production efficiency. As a result of our commitment to providing a high level of availability of the equipment used to provide compression services, we believe our service run times position us to satisfy the needs of our customers.

Access to External Expansion Capital

In determining the amount of cash available for distribution, the board of directors of our general partner will determine the amount of cash reserves to set aside for our operations, including reserves for future working capital, maintenance capital expenditures, expansion capital expenditures and other matters, which will impact the amount of cash we are able to distribute to our unitholders. However, we expect that we will rely primarily upon external financing sources, including borrowings under our revolving credit facility and issuances of debt and equity securities, rather than cash reserves, to fund our expansion capital expenditures. To the extent we are unable to finance growth externally and are unwilling to establish cash reserves to fund future expansions, our cash available for distribution will not significantly increase. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in the terms of our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units.

How We Evaluate Our Operations

Revenue Generating Horsepower

One of our measures of operational performance is the amount of revenue generating horsepower we are able to install monthly, quarterly and annually. Revenue generating horsepower growth is the primary driver for our revenue growth and it is also the base measure for evaluating our efficiency of capital deployed. Revenue generating horsepower is horsepower under contract for which we are billing a customer.

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Horsepower Utilization

Each month we identify idle compression units in our compression fleet and analyze their availability for redeployment. The primary reason for tracking and analyzing idle horsepower is to facilitate redeployment and therefore increase our contract operations revenue and efficiency of capital deployed. Our horsepower utilization is calculated as (i)(a) revenue generating horsepower plus (b) horsepower in our fleet that is under contract, but is not yet generating revenue plus (c) horsepower not yet in our fleet that is under contract not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Fleet horsepower utilization is calculated as (i) revenue generating horsepower divided by (ii) fleet horsepower.

Cost of Operations

We use cost of operations as a performance measure for each of our operating areas and the managers in charge of those operating areas. We track the items in cost of operations down to the compression unit level, and are able to compare operating costs to the budget we have for the type of horsepower and the area in which it is located. We use these comparisons to identify, research and address trends and variances. We also track our cost of operations on a company-wide basis, using month-to-month, year-to-date and year-to-year comparisons, and as compared to budget. This analysis is useful in identifying company-wide cost trends and allows us to take corrective actions as required.

Adjusted EBITDA

We view Adjusted EBITDA as one of our primary management tools, and we track this item on a monthly basis both as an absolute amount and as a percentage of revenue compared to the prior month, year-to-date and prior year and to budget. We define Adjusted EBITDA as our net income before interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar and certain fees and expenses related to the Holdings Acquisition. Adjusted EBITDA is used as a supplemental financial measure by our management and external users of our financial statements, such as investors and commercial banks, to assess:

- the financial performance of our assets without regard to the impact of financing methods, capital structure or historical cost basis of our assets;
- the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;
- the ability of our assets to generate cash sufficient to make debt payments and to make distributions; and
- our operating performance as compared to those of other companies in our industry without regard to the impact of financing methods and capital structure.

We believe that Adjusted EBITDA provides useful information to investors because, when viewed with our GAAP results and the accompanying reconciliations, it provides a more complete understanding of our performance than GAAP results alone. We also believe that external users of our financial statements benefit from having access to the same financial measures that management uses in evaluating the results of our business.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, our Adjusted EBITDA as presented may not be comparable to similarly titled measures of other companies.

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Adjusted EBITDA does not include interest expense, income taxes, depreciation expense, impairment of compression equipment, share-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar or certain fees and expenses related to the Holdings Acquisition. Because we borrow money under our revolving credit facility and have historically utilized operating leases to finance our operations, interest expense and operating lease expense are necessary elements of our costs. Because we use capital assets, depreciation and impairment of compression equipment is also a necessary element of our costs. Expense related to share-based compensation expense related to equity awards to employees is also necessary to operate our business. Therefore, measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income and net cash provided by operating activities determined under GAAP, as well as Adjusted EBITDA, to evaluate our financial performance and our liquidity. Our Adjusted EBITDA excludes some, but not all, items that affect net income, operating income and net cash provided by operating activities, and these measures may vary among companies. Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating this knowledge into management's decision-making processes.

Gross Operating Margin

Gross operating margin (defined as revenue less cost of operations, exclusive of depreciation and amortization expense) is a key measure for our business. Gross operating margin is impacted primarily by the pricing trends for our service operations and our cost of operations including labor rates for our service technicians, volume and per unit costs for our lubricant oils, quantity and pricing for our routine preventative maintenance to our compression units and property tax rates on our compression units. For a reconciliation of gross operating margin, a non-GAAP financial measure, to operating income, its most directly comparable financial measure calculated and presented in accordance with GAAP, see " Operating Highlights."

Accounting Terminology and Principles

Our discussion and analysis uses the following accounting terminology and principles:

Contract operations revenue. Contract operations revenue consists of gross revenue derived from the provision of compression services.

Parts and service revenue. Parts and service revenue represents revenues derived from repair services that are performed on compression units owned by our customers.

Cost of operations. Cost of operations consists of direct non-capitalized costs associated with the operation, repair and maintenance of compression units, engine and compressor frame lubrication oil costs, direct and indirect personnel related costs including salaries and benefits, operating expenses incurred in connection with our operating lease agreement with Caterpillar and other costs to support operational activities.

Selling, general and administrative expense. Selling, general and administrative, or SG&A, expense consists of centralized support functions such as accounting, payroll, treasury, insurance administration and risk management, marketing, sales, human resources, legal, information technology and other services.

Depreciation expense. Depreciation expense represents depreciation taken on the capitalized cost of asset additions beginning in the month the asset is placed in service. Depreciation is calculated on the straight-line method with various lives including 25-year lives for new compression units.

Amortization expense of intangible assets. Intangible assets consist of trade names and customer relationships that are amortized on a straight-line basis over their estimated useful lives, which is

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the period over which the assets are expected to contribute directly or indirectly to future cash flows. The estimated useful lives range from 25 to 30 years.

Operating Highlights

The following table summarizes certain horsepower and horsepower utilization percentages for the periods presented.

	Predecessor			Successor				
	Year Ended December 31,		Percent Change	Year Ended December 31,	Percent Change	Nine Months Ended September 30,		Percent Change
Operating Data (unaudited):	**2009**	**2010**	**2010**	**2011**	**2011**	**2011**	**2012**	**2012**
Fleet horsepower(1)	582,530	609,730	4.7%	722,201	18.4%	691,545	889,099	28.6%
Total available horsepower(2)	582,530	612,410	5.1%	809,418	32.2%	711,463	902,164	26.8%
Revenue generating horsepower(3)	502,177	533,692	6.3%	649,285	21.7%	591,290	786,750	33.1%
Average revenue generating horsepower(4)	489,243	516,703	5.6%	570,900	10.5%	551,566	735,639	33.4%
Revenue generating compression units	749	795	6.1%	888	11.7%	839	964	14.9%
Average horsepower per revenue generating compression unit(5)	655	667	1.8%	692	3.7%	683	784	14.8%
Horsepower utilization(6):								
At period end	92.0%	91.8%	(0.2)%	95.7%	4.2%	92.8%	93.4%	0.6%
Average for the period(7)	92.7%	92.6%	(0.1)%	92.3%	(0.3)%	91.4%	95.0%	3.9%

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of September 30, 2012, we had 31,630 of additional new compression unit horsepower on order, of which 23,135 horsepower has been delivered as of November 30, 2012 and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013.

(2) Total available horsepower is revenue generating horsepower under contract for which we are billing a customer, horsepower in our fleet that is under contract but is not yet generating revenue, horsepower not yet in our fleet that is under contract not yet generating revenue and that is subject to a purchase order and idle horsepower. Total available horsepower excludes new horsepower on order for which we do not have a compression services contract.

(3) Revenue generating horsepower is horsepower under contract for which we are billing a customer.

(4) Calculated as the average of the month-end horsepower per revenue generating horsepower for each of the months in the period.

(5)

Calculated as the average of the month-end horsepower per revenue generating compression unit for each of the months in the period.

(6)

Horsepower utilization is calculated as (i)(a) revenue generating horsepower plus (b) horsepower in our fleet that is under contract, but is not yet generating revenue plus (c) horsepower not yet in our fleet that is under contract not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Horsepower utilization based on revenue generating horsepower and fleet horsepower at each applicable period end was 86.2%, 87.5% and 89.9% for the years ended December 31, 2009, 2010 and 2011, respectively, and 85.5% and 88.5% for the nine months ended September 30, 2011 and 2012, respectively.

(7)

Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period.

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The increase in fleet horsepower as of December 31, 2011 compared to December 31, 2010 is attributable to the compression units added to our fleet to meet the incremental demand by new and current customers. Revenue generating horsepower increased by 21.7% from December 31, 2010 to December 31, 2011. The average horsepower per revenue generating compression unit increased from 667 to 692 between 2010 and 2011. The increase in fleet horsepower as of September 30, 2012 compared to September 30, 2011 is attributable to the compression units added to our fleet to meet the incremental demand by new and current customers. Revenue generating horsepower increased by 33.1% from September 30, 2011 to September 30, 2012. The average horsepower per revenue generating compression unit increased from 683 to 784, or 14.8%, over that same period.

	Predecessor			Successor				
	Year Ended December 31,		Percent Change	Year Ended December 31,	Percent Change	Nine Months Ended September 30,		Percent Change
Other Financial Data:	**2009**	**2010**	**2010**	**2011**	**2011**	**2011**	**2012**	**2012**
Gross Operating Margin(1)	$ 65,132	$ 58,736	(9.8)%	$ 59,115	0.6%	$ 42,270	$ 59,087	39.8%
Adjusted EBITDA(2)	$ 56,917	$ 51,987	(8.7)%	$ 51,285	(1.4)%	$ 37,162	$ 46,676	25.6%
Gross operating margin percentage(3)	68.4%	63.8%	(6.7)%	59.9%	(6.1)%	60.1%	67.9%	13.0%
Adjusted EBITDA percentage(3)	59.8%	56.5%	(5.5)%	51.9%	(8.1)%	52.8%	53.6%	1.5%

(1) Gross operating margin is a non-GAAP financial measure. We calculate gross operating margin as revenue less cost of operations, exclusive of depreciation and amortization expense. We believe that gross operating margin is useful as a supplemental measure of our operating profitability. Gross operating margin should not be considered an alternative to, or more meaningful than, operating income or any other measure of financial performance presented in accordance with GAAP. Moreover, gross operating margin as presented may not be comparable to similarly titled measures of other companies. Because we capitalize assets, depreciation and amortization of equipment is a necessary element of our costs. To compensate for the limitations of gross operating margin as a measure of our performance, we believe that it is important to consider operating income determined under GAAP, as well as gross operating margin, to evaluate our operating profitability.

The following table reconciles gross operating margin to operating income, its most directly comparable GAAP financial measure, for each of the periods presented:

	Predecessor		Successor		
	Year Ended December 31,		Year Ended December 31,	Nine Months Ended September 30,	
	2009	**2010**	**2011**	**2011**	**2012**
			(in thousands)		
Revenues:					
Contract operations	$ 93,178	$ 89,785	$ 93,896	$ 68,762	$ 85,285
Parts and service	2,050	2,243	4,824	1,565	1,730
Total revenues	95,228	92,028	98,720	70,327	87,015
Cost of operations, exclusive of depreciation and amortization	30,096	33,292	39,605	28,057	27,928
Gross operating margin	65,132	58,736	59,115	42,270	59,087
Other operating and administrative costs and expenses:					
Selling, general and administrative	9,136	11,370	12,726	8,500	12,927
Restructuring charges			300		
Depreciation and amortization	22,957	24,569	32,738	24,044	30,590
(Gain) loss on sale of assets	(74)	(90)	178	159	257
Impairment of compression equipment	1,677				
	33,696	35,849	45,942	32,703	43,774

Total other operating and administrative costs and expenses					
Operating income	$ 31,436	$ 22,887	$ 13,173	$ 9,567	$ 15,313

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(2)

For a reconciliation of Adjusted EBITDA, a non-GAAP financial measure, to net income and cash flows from operating activities, its most directly comparable GAAP financial measures, see "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures."

(3)

Gross operating margin percentage and Adjusted EBITDA percentage are calculated as a percentage of revenue.

Gross operating margin, as a percentage of total revenues, declined from 68% in 2009 to 64% in 2010. The decline in gross operating margin resulted from pricing pressure for compression services that began in 2009. While pricing for these services stabilized in mid-2010, compression units that were placed under service contracts during 2009 and 2010 were contracted at lower market rates. In addition, expenses related to our operating lease with Caterpillar were $2.3 million in 2010, or 2.5% of revenue, and $0.6 million in 2009, or 0.6% of revenue.

Gross operating margin, as a percentage of total revenues, declined from 64% in 2010 to 60% in 2011. The decline in gross operating margin was primarily attributable to continued cost increases for providing our compression services. Increased expenses related to the addition of new compression units in 2011 under our operating lease with Caterpillar, which were $2.3 million in 2010, or 2.5% of revenue, as compared to $4.1 million in 2011, or 4.1% of revenue. On December 15, 2011, we purchased all the compression units we previously leased from Caterpillar for $43 million and terminated all the lease schedules and covenants under the facility. In addition, expenses related to fluids increased from $4.3 million in 2010, or 4.7% of revenue, to $5.1 million in 2011, or 5.2% of revenue. This increase was due to a 21.4% increase in fluids supplier pricing during 2011 as compared to 2010, offset by a 1.3% decrease in gallons used in 2011. Other significant increases in expenses included (1) maintenance expenses increased by $0.3 million, or 0.1% of revenue, (2) truck fleet fuel expenses increased by $0.4 million, or 0.3% of revenue, (3) supplies and equipment expenses increased by $0.2 million, or 0.2% of revenue, and (4) operating personnel salaries and benefits expense increased $0.4 million, each of which were attributable to the increase in the size of our fleet horsepower. Additionally, a portion of retail service revenue, including billings for trucking and crane services increased $1.1 million during 2011, including $1.0 million recognized during the fourth quarter of 2011, due to the deployment and redeployment of compression units. These ancillary trucking and crane services, all of which are billed to customers, resulted in no gross operating margin.

Gross operating margin, as a percentage of total revenues, increased from 60% for the nine months ended September 30, 2011 to 68% for the nine months ended September 30, 2012. The increase in gross operating margin was primarily attributable to a 23.7% increase in total revenues when comparing the periods, and a slight decrease in cost of operations of 0.5%. Average revenue generating horsepower increased from 551,566 for the nine months ended September 30, 2011 to 735,639 for the nine months ended September 30, 2012, an increase of 33.4%. Average revenue per revenue generating horsepower per month declined from $14.21 for the nine months ended September 30, 2011 to $13.39 for the nine months ended September 30, 2012, a decrease of 5.8%. The decline in average revenue per revenue generating horsepower per month related primarily to the 14.8% increase in average horsepower per revenue generating compression unit from 683 for the nine months ended September 30, 2011 to 784 for the nine months ended September 30, 2012. The decrease in cost of operations is attributable to a $3.3 million decrease in equipment operating lease expense, as the Caterpillar operating lease schedules were terminated on December 15, 2011. Significant cost increases offset the decrease related to the Caterpillar operating lease, and consisted of (1) a $0.9 million increase in lubrication oil expenses due to both 9.7% increase in the average supplier price per gallon and 14.4% increase in gallons consumed, (2) a $0.5 million increase in labor maintenance, (3) a $0.4 million increase related to vehicle tools and gasoline, (4) a $0.6 million increase related to total labor expense and (5) a $0.1 million increase of field and warehouse supplies expense, all of which were attributable to the increase in the size of our fleet.

Gross operating margin, as a percentage of total revenues, increased from 60% for the year ended December 31, 2011 to 68% for the nine months ended September 30, 2012. The increase was primarily

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attributable to an increase in revenue generating horsepower from 649,285 at December 31, 2011 to 786,750 at September 30, 2012, or a 21.2% increase. Higher revenue levels were partially offset by an increase in selling, general and administrative expense during the noted periods due to an increase in employee headcount to support operations and sales management and certain executive positions to operate as a public company. Selling, general and administrative expense represented 12.9% and 14.9% of revenue for the year ended December 31, 2011 and the nine months ended September 30, 2012, respectively.

Financial Results of Operations

Nine months ended September 30, 2012 compared to the nine months ended September 30, 2011

The following table summarizes our results of operations for the periods presented:

	Nine months ended September 30,		Percent Change
	2011	2012	
	(in thousands)		
Revenue:			
Contract operations	$ 68,762	$ 85,285	24.0%
Parts and service	1,565	1,730	10.5%
Total revenues	70,327	87,015	23.7%
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	28,057	27,928	(0.5)%
Selling, general and administrative	8,500	12,927	52.1%
Depreciation and amortization	24,044	30,590	27.2%
Loss on sale of assets	159	257	61.6%
Total costs and expenses	60,760	71,702	18.0%
Operating income	9,567	15,313	60.1%
Other income (expense):			
Interest expense	(9,424)	(11,637)	23.5%
Other	17	23	35.3%
Total other expense	(9,407)	(11,614)	23.5%
Income before income tax expense	160	3,699	2,211.9%
Income tax expense	111	144	29.7%
Net income	$ 49	$ 3,555	7,155.1%

Contract operations revenue. Contract operations revenue was $85.3 million for the nine months ended September 30, 2012 compared to $68.8 million during the same period in 2011, an increase of 24.0%. Average revenue generating horsepower increased from 551,566 for the nine months ended September 30, 2011 to 735,639 for the nine months ended September 30, 2012, an increase of 33.4%. Average revenue per revenue generating horsepower per month declined from $14.21 for the nine months ended September 30, 2011 to $13.39 for the nine months ended September 30, 2012, a decrease of 5.8%. The decline in average revenue per revenue generating horsepower per month related primarily to the 14.8% increase in average horsepower per revenue generating compression unit from 683 for the nine months ended September 30, 2011 to 784 for the nine months ended September 30, 2012. During the nine month period ended September 30, 2012, we had a higher level of partial month billings and standby rates with certain customers in our revenues compared to that same period for

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2011. Revenue generating horsepower was 786,750 at September 30, 2012 compared to 591,290 at September 30, 2011, a 33.1% increase.

Parts and service revenue. Parts and service revenue was $1.7 million for the nine months ended September 30, 2012 compared to $1.6 million during the same period in 2011, a 10.5% increase.

Cost of operations, exclusive of depreciation and amortization. Cost of operations was $27.9 million for the nine months ended September 30, 2012 compared to $28.1 million for the nine months ended September 30, 2011, a decrease of 0.5%. The decrease is attributable to a $3.3 million decrease in equipment operating lease expense, as the Caterpillar operating lease schedules were terminated on December 15, 2011. Significant cost increases offset the decrease related to the Caterpillar operating lease, and consisted of (1) a $0.9 million increase in lubrication oil expenses due to both 9.7% increase in the average supplier price per gallon and 14.4% increase in gallons consumed, (2) a $0.5 million increase in labor maintenance, (3) a $0.4 million increase related to vehicle tools and gasoline, (4) a $0.6 million increase related to total labor expense and (5) a $0.1 million increase of field and warehouse supplies expense, all of which were attributable primarily to the increase in the size of our fleet. The cost of operations was 32.1% of revenue for the nine months ended September 30, 2012 as compared to 39.9% for the nine months ended September 30, 2011.

Selling, general and administrative expense. Selling, general and administrative expense was $12.9 million for the nine months ended September 30, 2012 compared to $8.5 million for the nine months ended September 30, 2011, an increase of 52.1%. Selling, general and administrative expense represented 14.9% and 12.1% of revenue for the nine months ended September 30, 2012 and 2011, respectively. Approximately $1.7 million of the increase in selling, general and administrative expense related to salaries increase due to an increase in employee headcount to support operations and sales management and certain executive positions to operate as a public company. Management fees for services provided by an affiliate of our general partner increased $0.5 million due to the closing of the third amendment and fourth and restated amended credit facility along with other increased services during the nine months ended September 30, 2012. Additionally, accounting fees increased $0.4 million due to increased services as we prepare to operate as a public company. Other significant increases include (1) a $0.2 million due to increased office rent, (2) a $0.3 million due to increased sales support costs and (3) a $0.4 million of increased outside services costs, all of which were attributable to increased employee headcount and support services. The selling, general and administrative employee headcount was 59 at September 30, 2012, a 25.5% increase from September 30, 2011. The selling, general and administrative employee headcount increased to support the continued growth of the business.

Depreciation and amortization expense. Depreciation and amortization expense was $30.6 million for the nine months ended September 30, 2012 compared to $24.0 million for the nine months ended September 30, 2011, an increase of 27.2%. The increase was related to an increase in property, plant and equipment of 49.3% over these periods.

Interest expense. Interest expense was $11.6 million for the nine months ended September 30, 2012 compared to $9.4 million for the nine months ended September 30, 2011, an increase of 23.5%. Included in interest expense is amortization of deferred loan costs of $1.4 million and $0.8 million for the nine months ended September 30, 2012 and 2011, respectively. Average borrowings outstanding under our revolving credit facility were $425.0 million for the nine months ended September 30, 2012 compared to $262.2 million for the nine months ended September 30, 2011. Interest expense for both periods was related to borrowings under our revolving credit facility. Our revolving credit facility had an interest rate of 2.98% and 3.97% at September 30, 2012 and 2011, respectively. The composite fixed interest rate for $75 million and $140.0 million of notional coverage under interest rate swap instruments was 3.00% and 2.52% at September 30, 2012 and 2011, respectively.

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Income tax expense. We accrued approximately $144,000 and $111,000 in franchise tax for the nine months ended September 30, 2012 and 2011, respectively, as a result of the Texas franchise tax (applicable to income apportioned to Texas beginning January 1, 2007). This tax is reflected in our financials as income tax in accordance with FASB ASC 740, which requires this classification for reporting purposes.

Year ended December 31, 2011 compared to the year ended December 31, 2010

The following table summarizes our results of operations for the periods presented:

	Predecessor	Successor	
	Year ended December 31,		
	2010	2011	Percent Change
	(in thousands)		
Revenues:			
Contract operations	$ 89,785	$ 93,896	4.6%
Parts and service	2,243	4,824	115.1%
Total revenues	92,028	98,720	7.3%
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	33,292	39,605	19.0%
Selling, general and administrative	11,370	12,726	11.9%
Restructuring charges		300	
Depreciation and amortization	24,569	32,738	33.2%
(Gain) loss on sale of assets	(90)	178	
Total costs and expenses	69,141	85,547	23.7%
Operating income	22,887	13,173	(42.4)%
Other income (expense):			
Interest expense	(12,279)	(12,970)	5.6%
Other	26	21	(19.2)%
Total other expense	(12,253)	(12,949)	5.7%
Income before income tax expense	10,634	224	(97.9)%
Income tax expense	155	155	0.0%
Net income	$ 10,479	$ 69	(99.3)%

Contract operations revenue. Contract operations revenue was $93.9 million for the year ended December 31, 2011 compared to $89.8 million in 2010, an increase of 4.6%. Average revenue generating horsepower increased from 516,703 for the year ended December 31, 2010 to 570,900 for the year ended December 31, 2011, an increase of 10.5%. Average revenue per revenue generating horsepower per month declined from $14.70 for the year ended December 31, 2010 to $14.07 for the year ended December 31, 2011, a decrease of 4.3%. The decline in average revenue per revenue generating horsepower per month related primarily to the 3.7% increase in the estimated average horsepower per revenue generating compression unit, which was 667 and 692 at December 31, 2010 and 2011, respectively. While pricing for these services stabilized in mid-2010, compression units that were placed under service contracts during 2009 and 2010 were contracted at lower market rates. There were 888 revenue generating compression units at December 31, 2011 compared to 795 at December 31, 2010, an 11.7% increase. Revenue generating horsepower was 649,285 at December 31, 2011 compared to 533,692 at December 31, 2010, a 21.7% increase.

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Parts and service revenue. Parts and service revenue was $4.8 million for the year ended December 31, 2011 compared to $2.2 million in 2010, or a 115.1% increase. Retail parts revenue increased $1.5 million during 2011 after our customers curtailed this work with us in 2010. A portion of retail service revenue, including billings for trucking and crane services increased $1.1 million during 2011, including $1.0 million recognized during the fourth quarter of 2011, due to the deployment and redeployment of compression units. These ancillary trucking and crane services, all of which are billed to customers, result in no gross operating margin.

Cost of operations, exclusive of depreciation and amortization. Cost of operations was $39.6 million for the year ended December 31, 2011 compared to $33.3 million for the year ended December 31, 2010, an increase of 19.0%. Approximately $1.8 million of this increase was related to higher expense levels under our operating lease facility with Caterpillar due to the addition of new compression units over the applicable periods. The amount drawn under this operating lease facility immediately prior to the termination of these lease schedules on December 15, 2011 was $39.9 million as compared to $28.9 million as of December 31, 2010. Approximately $0.8 million of the increase in cost of operations was related to higher lubrication oil expenses. Lubrication oil expenses increased due to a 21.4% increase in the average supplier price per gallon, offset by a 1.3% decrease in gallons consumed. Freight costs, all of which was billed to customers, increased $1.1 million due to the redeployment of compression units during the year ended December 31, 2011, as discussed above. Retail parts expense increased $1.1 million due to the sale of six spare engines. Other significant increases include (1) maintenance expenses increased by $0.3 million, (2) truck fleet fuel expenses increased by $0.4 million, (3) supplies and equipment expenses increased by $0.2 million and (4) operating personnel salaries and benefits expense increased $0.4 million, all of which were attributable to the increase in the size of our fleet. The cost of operations was 40.2% of revenue for the year ended December 31, 2011 as compared to 36.2% for the year ended December 31, 2010.

Selling, general and administrative expense. Selling, general and administrative expense was $12.7 million for the year ended December 31, 2011 compared to $11.4 million for the year ended December 31, 2010, an increase of 11.9%. Selling, general and administrative expense represented 12.9% and 12.4% of revenue for the year ended December 31, 2011 and 2010, respectively. Approximately $1.0 million of the increase in selling, general and administrative expense relates to a fee for management services provided by an affiliate of our general partner, which we expect will not be paid by us after this offering. The selling, general and administrative employee headcount was 51 at December 31, 2011, a 30.8% employee increase from December 31, 2010, resulting in $0.7 million increase in salary and benefit expenses. The selling, general and administrative employee headcount increased to support continued growth of the business.

Restructuring charges. During the year ended December 31, 2011, we incurred $0.3 million of restructuring charges for severance and retention benefits related to the termination of certain administrative employees. These charges are reflected as restructuring charges in our consolidated statement of operations for the year ended December 31, 2011. We expect to pay these restructuring charges in 2012.

Depreciation and amortization expense. Depreciation and amortization expense was $32.7 million for the year ended December 31, 2011 compared to $24.6 million for the year ended December 31, 2010, an increase of 33.2%. The push-down accounting treatment for the Holdings Acquisition resulted in the recognition of identified intangibles for customer relationships and the USA Compression trade name as of December 31, 2010 and the amortization of these identified intangibles over their useful lives began on January 1, 2011, of which $3.0 million was recognized for the year ended December 31, 2011. The remaining increase was related to an increase in property, plant and equipment over these periods.

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Interest expense. Interest expense was $13.0 million for the year ended December 31, 2011 compared to $12.3 million for the year ended December 31, 2010, an increase of 5.6%. Included in interest expense is amortization of deferred loan costs of $1.5 million and $3.4 million for the years ended December 31, 2011 and 2010, respectively. Interest expense for both periods was related to borrowings under our revolving credit facility. Average borrowings outstanding under our revolving credit facility were $275.1 million for the year ended December 31, 2011 compared to $249.1 million for the year ended December 31, 2010. Our revolving credit facility had an interest rate of 3.02% and 3.76% at December 31, 2011 and 2010, respectively, and an average interest rate of 3.71% and 2.06%, excluding the effects from the interest rate swap instruments discussed below, for the year then ended, respectively, with the higher interest rate at December 31, 2011 due to the amendment of our revolving credit facility in December 2010. The November 2011 amendment to our credit facility increased the overall commitments under the facility from $400 million to $500 million and reduced our applicable margin for LIBOR loans from a range of 300 to 375 basis points above LIBOR to a range of 200 to 275 basis points above LIBOR, depending on our leverage ratio. The composite fixed interest rate for $140 million of notional coverage under three interest rate swap instruments was 2.52% at December 31, 2011 and 2010 plus the applicable margin of 2.75% and 3.50% at December 31, 2011 and December 31, 2010, respectively. As of December 31, 2010, we no longer designate our swap agreements as cash flow hedges. As a result, amounts paid or received from the interest rate swaps are charged or credited to interest expense. For the year ended December 31, 2011, we recorded a fair value gain of $2.6 million with respect to these swaps as a reduction in interest expense.

Income tax expense. We accrued approximately $155,000 in franchise tax for the years ended December 31, 2011 and 2010, as a result of the Texas franchise tax.

Year ended December 31, 2010 compared to the year ended December 31, 2009

The following table summarizes our results of operations for the periods presented:

	Predecessor Year Ended December 31,		Percent Change
	2009	2010	
	(in thousands)		
Revenues:			
Contract operations	$ 93,178	$ 89,785	(3.6)%
Parts and service	2,050	2,243	9.4%
Total revenues	95,228	92,028	(3.4)%
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	30,096	33,292	10.6%
Selling, general and administrative	9,136	11,370	24.5%
Depreciation and amortization	22,957	24,569	7.0%
(Gain) loss on sale of assets	(74)	(90)	21.6%
Impairment of compression equipment	1,677		
Total costs and expenses	63,792	69,141	8.4%
Operating income	31,436	22,887	(27.2)%
Other income (expense):			
Interest expense	(10,043)	(12,279)	22.3%
Other	25	26	4.0%
Total other expense	(10,018)	(12,253)	22.3%
Income before income tax expense	21,418	10,634	(50.4)%
Income tax expense	190	155	(18.4)%
Net income	$ 21,228	$ 10,479	(50.6)%

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Contract operations revenue. Contract operations revenue was $89.8 million for the year ended December 31, 2010 compared to $93.2 million for the year ended December 31, 2009, a decrease of 3.6%. Average revenue generating horsepower increased from 489,243 for the year ended December 31, 2009, to 516,703 for the year ended December 31, 2010, an increase of 5.6%. Average revenue per revenue generating horsepower per month declined from $16.05 for the year ended December 31, 2009, to $14.70 for the year ended December 31, 2010, a decrease of 8.4%. The decline in revenue per revenue generating horsepower per month related to general pricing pressure for compression revenue that began in 2009. While pricing for these services stabilized in mid-2010, compression units that were placed under service contracts during 2009 and 2010 were placed at lower market rates. There were 795 revenue generating compression units at December 31, 2010 compared to 749 at December 31, 2009, a 6.1% increase. Revenue generating horsepower was 533,692 at December 31, 2010 compared to 502,177 at December 31, 2009, a 6.3% increase.

Parts and service revenue. Parts and service revenue was $2.2 million for the year ended December 31, 2010 compared to $2.1 million for the year ended December 31, 2009, a 9.4% increase.

Cost of operations, exclusive of depreciation and amortization. Cost of operations was $33.3 million for the year ended December 31, 2010 compared to $30.1 million for the year ended December 31, 2009, an increase of 10.6%. Approximately $1.7 million of this increase was related to higher expense levels under our operating lease facility with Caterpillar. The amount drawn under this operating lease facility was $28.9 million as of December 31, 2010 as compared to $14.9 million as of December 31, 2009. Indirect operating expenses increased approximately $1.1 million for 2010 as compared to 2009 including field warehouse supplies, property taxes and our service technician vehicle fleet due to the increase in our compression unit fleet horsepower. The cost of operations was 36.2% of revenue for the year ended December 31, 2010 as compared to 31.6% for the year ended December 31, 2009.

Selling, general and administrative expense. Selling, general and administrative expense was $11.4 million for the year ended December 31, 2010 compared to $9.1 million for the year ended December 31, 2009, an increase of 24.5%. Selling, general and administrative expense represented 12.4% and 9.6% of revenue for the years ended December 31, 2010 and 2009, respectively. The selling, general and administrative employee headcount was 39 employees at December 31, 2010, level with the headcount at December 31, 2009. Selling, general and administrative expenses in 2010 included $1.8 million related to legal fees incurred by us in connection with the Holdings Acquisition.

Depreciation and amortization expense. Depreciation and amortization expense was $24.6 million for the year ended December 31, 2010 compared to $23.0 million for the year ended December 31, 2009, an increase of 7.0%, which resulted from an increase in property, plant and equipment in 2009 and 2010 and a change in the estimated useful lives of our vehicles in July 2009.

Interest expense. Interest expense was $12.3 million for the year ended December 31, 2010, compared to $10.0 million for the year ended December 31, 2009, an increase of 22.3%. Included in interest expense is amortization of deferred loan costs of $3.5 million and $0.4 million for the years ended December 31, 2010 and 2009, respectively. Interest expense for both periods was related to borrowings under our revolving credit facility. Average borrowings outstanding under our revolving credit facility were $249.1 million for the year ended December 31, 2010 compared to $270.3 million for the year ended December 31, 2009. Our revolving credit facility had an interest rate of 3.76% and 1.99% at December 31, 2010 and 2009, respectively, and an average interest rate of 2.06% in 2010 and 2.10% in 2009, excluding the effects from the interest rate swap instruments. The composite fixed interest rate for $140 million of notional coverage under three interest rate swap instruments was 2.52% at December 31, 2010 and 2009 plus the applicable margin of 1.75%.

Income tax expense. We accrued approximately $155,000 in franchise tax for the year ended December 31, 2010, and $190,000 for the year ended December 31, 2009, as a result of the Texas franchise tax.

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Effects of Inflation

In 2011, 2010 and 2009, even though the price for lubrication oil, gasoline, insurance and the capital cost of engines steadily increased, these increases did not adversely impact our overall results of operations. We have the ability to manage the effects of these price increases through rate adjustments in new service contracts, as well as through Consumer Price Index adjustments in most existing customer contracts. The primary price increases experienced for the period from January 1, 2009 to December 31, 2011 were the following: the hourly labor rate for certain classes of our service technicians had a composite increase of 6.0%; the price of lubrication oil per gallon decreased approximately 6.1%, but gallons consumed has increased 2.0%; for similarly configured 3516 type compression units, our price increased 8.0% for new compression units purchased during the quarter ended December 31, 2011 as compared to new compression units purchased during the quarter ended March 31, 2009.

Liquidity and Capital Resources

Historically, our sources of liquidity have been cash generated from operations and third-party financing. As of September 30, 2012, total cash and cash equivalents was $6,500 compared to $3,000 at December 31, 2011, 2010 and 2009. Total liquidity, comprised of cash and availability of long-term borrowings, was $91.3 million at September 30, 2012 compared to $39.0 million, $66.0 million and $44.6 million as of December 31, 2011, 2010 and 2009, respectively.

We have a $600 million revolving credit facility that matures on October 5, 2015. Commitments under our revolving credit facility increased from $305 million to $400 million in December 2010, from $400 million to $500 million on November 16, 2011 and from $500 million to $600 million on June 1, 2012. Availability under the revolving credit facility is determined by reference to the calculated borrowing base, up to the commitment amount, less the outstanding balance under the revolving credit facility. See " Description of Revolving Credit Facility." The net proceeds from this offering will be used to repay indebtedness under our revolving credit facility. We incurred indebtedness to fund capital expenditures and for working capital needs. We would have had approximately $301.4 million outstanding under the revolving credit facility as of September 30, 2012 after giving effect to the closing of this offering and the application of the net proceeds as discussed under "Use of Proceeds."

The amount of available cash we need to pay the minimum quarterly distributions for four quarters on our common units, subordinated units and the 2.0% general partner interest outstanding immediately after this offering is approximately $50.5 million. Our pro forma available cash to make distributions during the year ended December 31, 2011 and the twelve months ended September 30, 2012 would have been sufficient to allow us to pay 100% of the minimum quarterly distribution on our common units and 30.5% and 40.7%, respectively, of the minimum quarterly distribution on our subordinated units during the period.

In addition to distributions on our equity interests, our primary short-term liquidity needs will be to fund general working capital requirements, while our long-term liquidity needs will primarily relate to expansion capital expenditures. We believe that cash from operations will be sufficient to meet our existing short-term liquidity needs for at least the next 12 months.

Our long-term liquidity needs will generally be funded from cash from operations, borrowings under our revolving credit facility and other debt or equity financings. We cannot assure you that we will be able to raise additional funds on favorable terms. For more information, please read " Capital Expenditures" below.

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The following table summarizes our sources and uses of cash for the periods presented:

	Predecessor		Successor		
	Year Ended December 31,		Year Ended December 31,	Nine Months Ended September 30,	
	2009	2010	2011	2011	2012
			(in thousands)		
Net cash provided by operating activities	$ 42,945	$ 38,572	$ 33,782	$ 28,673	$ 30,375
Net cash used in investing activities	(26,763)	(18,768)	(140,444)	(64,379)	(147,121)
Net cash provided by (used in) financing activities	(16,545)	(19,804)	106,662	35,706	116,749

Net cash provided by operating activities. Net cash provided by operating activities increased to $30.4 million for the nine months ended September 30, 2012, from $28.7 million for the nine months ended September 30, 2011. The increase related primarily to a higher income level in 2012, offset by a $8.8 million higher use of working capital in 2012 due to increased purchases and timing of payments for new compression unit equipment.

Net cash provided by operating activities decreased to $33.8 million for the year ended December 31, 2011, from $38.6 million in 2010. The decrease related primarily to a lower income level, offset by $1.9 million of working capital generated for the year ended December 31, 2011.

Net cash provided by operating activities decreased to $38.6 million for the year ended December 31, 2010, from $42.9 million for the year ended December 31, 2009. The decrease related primarily to a lower income level in 2010, offset by the purchase of engines in 2009 totaling $3.3 million.

Net cash used in investing activities. Net cash used in investing activities increased to $147.1 million for the nine months ended September 30, 2012, from $64.4 million for the nine months ended September 30, 2011. The increase related primarily to higher capital expenditures of $148.5 million during the nine months ended September 30, 2012, offset by $0.6 million of higher proceeds from the sale of equipment during the nine months ended September 30, 2012.

Net cash used in investing activities increased to $140.4 million for the year ended December 31, 2011, from $18.8 million in 2010. The increase related to capital expenditures of $133.3 million and a compression unit purchase deposit of $8.0 million, for the year ended December 31, 2011, offset by the collection of funds in this period of $0.8 million related to the sale of compression units, 6 engines, and trucks.

Net cash used in investing activities decreased to $18.8 million for the year ended December 31, 2010, from $26.8 million for the year ended December 31, 2009. The decrease primarily related to lower capital expenditures for compression equipment in 2010. Approximately $13.9 million and $14.9 million of compression equipment was funded under our operating lease facility with Caterpillar in 2010 and 2009, respectively.

Net cash provided by (used in) financing activities. Net cash provided by financing activities increased to $116.7 million for the nine months ended September 30, 2012, from $35.7 million for the nine months ended September 30, 2011. The change was due to lower borrowings under our revolving credit facility for the nine months ended September 30, 2011 versus higher borrowings during 2012, due to higher levels of growth capital expenditures.

Net cash provided by financing activities was $106.7 million for the year ended December 31, 2011, compared to net cash used in financing activities of $19.8 million in 2010. The change was due to net repayments of borrowings under our revolving credit facility for the year ended December 31, 2010 versus net borrowings during 2011, due to higher levels of growth capital expenditures.

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Net cash used in financing activities increased to $19.8 million for the year ended December 31, 2010, from $16.5 million for the year ended December 31, 2009. The increase was a result of a lower level of net repayments of borrowings under our revolving credit facility of $4.4 million offset by financing costs of $8.1 million related to the upsizing and extending of our revolving credit facility on December 23, 2010 in connection with the Holdings Acquisition.

Capital Expenditures

The compression business is capital intensive, requiring significant investment to maintain, expand and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate that our capital requirements will continue to consist primarily of, the following:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets, to maintain the operating capacity of our assets and extend their useful lives, or other capital expenditures that are incurred in maintaining our existing business and related cash flow; and

- expansion capital expenditures, which are capital expenditures made to expand the operating capacity or revenue generating capacity of existing or new assets, including by acquisition of compression units or through modification of existing compression units to increase their capacity.

We expect that our maintenance capital expenditure requirements will continue to increase as the overall size and age of our fleet increases. Our aggregate maintenance capital expenditures for the year ended December 31, 2011 were $9.0 million and we estimate that our aggregate maintenance capital expenditures for the year ending December 31, 2013 will be approximately $15.4 million.

Given our growth objective, we anticipate that we will continue to make significant expansion capital expenditures. Our expansion capital expenditures were $124.3 million for the year ended December 31, 2011 and we estimate that our expansion capital expenditures will be approximately $94.2 million for the year ending December 31, 2013, consisting of the acquisition of new compression units and related equipment. On December 16, 2011, we entered into an agreement with one of our compression equipment suppliers to reduce certain previously made progress payments by $8 million and received a credit. We applied this $8 million credit to new compression units purchased from this supplier in the nine months ended September 30, 2012. Before the application of this credit, expansion capital expenditures were $146.7 million and maintenance capital expenditures were $9.8 million for the nine months ended September 30, 2012.

In addition to organic growth, we may also consider a variety of assets or businesses for potential acquisition. We expect to fund any future acquisitions primarily with capital from external financing sources and issuance of debt and equity securities, including our issuance of additional partnership units and future debt offerings given market conditions.

Description of Revolving Credit Facility

We amended our revolving credit agreement in December 2010 to increase the overall commitments under the facility to $400 million and extend the term until October 5, 2015. On November 16, 2011, we amended the revolving credit agreement to increase the overall commitments under the facility from $400 million to $500 million and reduce our applicable margin for LIBOR loans from the previous range of 300 to 375 basis points above LIBOR to the new range of 200 to 275 basis points above LIBOR, depending on our leverage ratio. We further amended our revolving credit agreement on June 1, 2012 to increase the overall commitments under the facility from $500 million to $600 million. We have the option to increase the overall commitments under our revolving credit agreement by an additional $50 million, subject to receipt of lender commitments and satisfaction of other conditions.

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The revolving credit facility is available for our general partnership purposes, including working capital, capital expenditures, and distributions. Pro forma for this offering, we would have had approximately $301.4 million outstanding under the revolving credit facility as of September 30, 2012. Please read "Use of Proceeds."

On June 1, 2012, we entered into the amended and restated credit agreement in order to provide a covenant structure that is more appropriate for a public company than is our current credit agreement. On December 10, 2012, we amended the fourth amended and restated credit agreement to extend the periods during which the maximum funded debt to EBITDA ratio thresholds will apply. Borrowing availability under our amended and restated credit agreement will continue to be linked to our asset base, with the increased maximum capacity of $600,000,000 (subject to a further potential increase of $50,000,000). The revolving credit facility will continue to be secured by a first priority lien against our assets and mature on October 5, 2015, at which point all amounts outstanding will become due.

Interest will continue to be due and payable in arrears and calculated, at our option, on either a floating rate basis, payable monthly or on a LIBOR basis, payable at the end of the applicable LIBOR period (1, 2, 3 or 6 months), but no less frequently than quarterly. LIBOR borrowings will bear interest at LIBOR for the applicable period plus a margin of 2.50% to 1.75% based on our leverage ratio of funded debt to consolidated EBITDA, each as defined in the amended and restated credit agreement. Floating rate borrowings will bear interest at a rate per annum that is the higher of bank prime rate, the federal funds rate plus 0.50% or the LIBOR rate for a 1 month period plus 1%, without additional margin. The revolving credit facility will include a $20,000,000 sub-line for issuing letters of credit for a fee at a per annum rate equal to the margin for LIBOR borrowings on the average daily undrawn stated amount of each letter of credit issued under the facility.

Our amended and restated credit agreement will permit us to make distributions of available cash to unitholders so long as (a) no default or event of default under the facility occurs or would result from the distribution, (b) immediately prior to and after giving effect to such distribution, we are in compliance with the facility's financial covenants and (c) immediately after giving effect to such distribution, we have availability under the credit facility of at least $20,000,000. In addition, the amended and restated credit agreement will contain various covenants that may limit, among other things, our ability to:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- subject to exceptions, enter into transactions with affiliates;
- sell our assets; or
- acquire additional assets.

Our amended and restated credit agreement also will contain financial covenants requiring us to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0; and
- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter, for the twelve month period then ending of (a) 5.50 to 1.0, with respect to any fiscal quarter ending on or after the closing of the offering through March 31, 2014 or (b) 5.00 to 1.0, with respect to the fiscal quarter ending June 30, 2014 and each fiscal quarter thereafter, in each case subject to a provision for increases to such thresholds by 0.5 in connection with certain future

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acquisitions for the six-consecutive month period following the period in which any such acquisition occurs.

If an event of default exists under our amended and restated credit agreement, the lenders will be able to accelerate the maturity of the amended and restated credit agreement and exercise other rights and remedies.

The effectiveness of our amended and restated credit agreement is subject to the closing of this offering.

We are in compliance with all of the covenants under our current credit agreement.

Total Contractual Cash Obligations. The following table summarizes our total contractual cash obligations as of September 30, 2012:

	Payments Due by Period				
Contractual Obligations	**Total**	**1 year**	**2 - 3 years**	**4 - 5 years**	**More than 5 years**
			(in thousands)		
Long-term debt(1)	$ 482,137	$	$	$ 482,137	$
Interest on long-term debt obligations(2)	43,300	14,368	28,735	197	
Equipment/capital purchases(3)	52,614	52,614			
Operating lease obligations(4)	4,335	1,049	1,543	1,366	377
Total contractual cash obligations	$ 582,386	$ 68,031	$ 30,278	$ 483,700	$ 377

(1) Represents future principal repayments under our revolving credit facility.

(2) Represents future interest payments under our revolving credit facility based on the interest rate at September 30, 2012 of 2.98%.

(3) Represents commitments for new compression units that are being fabricated.

(4) Represents commitments for future minimum lease payments for noncancelable leases. We signed two new significant leases during the three months ended September 30, 2012 for office space which contributed $2,206,430 to the total future lease payments.

Pro forma for this offering, we would have had approximately $301.4 million outstanding under the revolving credit facility as of September 30, 2012. We anticipate subsequent borrowings under this revolving credit facility to fund interest payments, capital expenditures, including the acquisition of additional new compression units, and distributions.

Off Balance Sheet Arrangements

We have not entered into any transactions, agreements or other contractual arrangements that would result in off-balance sheet liabilities.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon our financial statements. These financial statements were prepared in conformity with U.S. GAAP. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates; however, actual results may differ from these estimates under different assumptions or conditions. The accounting policies that we believe

require management's most difficult, subjective or complex judgments and are the most critical to its reporting of results of operations and financial position are as follows:

Depreciation

Property and equipment are stated at cost. Depreciation for financial reporting purposes is computed on the straight-line basis using estimated useful lives. If the actual useful life of our property and equipment is less than the estimate used for purposes of computing depreciation expense, we could experience an acceleration in depreciation expense. Major overhauls and improvements that extend the life of an asset are capitalized. As of September 30, 2012, we had 1,136 compression units that were subject to depreciation. Given the large number of compression units being depreciated, the impact of a particular unit incurring an actual useful life that is less than the estimated useful life would not have a material impact on our results of operations.

Business Combinations and Goodwill

Goodwill acquired in connection with business combinations represents the excess of consideration over the fair value of net assets acquired. Certain assumptions and estimates are employed in determining the fair value of assets acquired and liabilities assumed, as well as in determining the allocation of goodwill to the appropriate reporting unit.

We perform an impairment test for goodwill annually or earlier if indicators of potential impairment exist. Our goodwill impairment test involves a comparison of the fair value of its reporting unit with its carrying value. The fair value is determined using discounted cash flows and other market-related valuation models. Certain estimates and judgments are required in the application of the fair value models. As of December 31, 2010, we performed an impairment analysis and determined that no impairment had occurred. If for any reason the fair value of our goodwill declines below the carrying value in the future, we may incur charges for the impairment. There was no impairment recorded for goodwill for the years ended December 31, 2010 and 2011 or the nine months ended September 30, 2012.

Long-Lived Assets

Long-lived assets, which include property and equipment, and intangible assets comprise a significant amount of our total assets. Long-lived assets to be held and used by us are reviewed to determine whether any events or changes in circumstances indicate the carrying amount of the asset may not be recoverable. For long-lived assets to be held and used, we base our evaluation on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flows analysis. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the estimated fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on an estimate of discounted cash flows. There was no impairment recorded for the years ended December 31, 2011 and 2010 or the nine months ended September 30, 2012, and an impairment of $1.7 million was recorded for the year ended December 31, 2009.

Allowances and Reserves

We maintain an allowance for bad debts based on specific customer collection issues and historical experience. On an ongoing basis, we conduct an evaluation of the financial strength of our customers based on payment history and specific identification and makes adjustments to the allowance as

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necessary. The allowance for doubtful accounts was $177,192, $260,598 and $173,808 at September 30, 2012, December 31, 2011 and 2010, respectively.

Revenue Recognition

Revenue is recognized by us using the following criteria: (i) persuasive evidence of an arrangement, (ii) delivery has occurred or services have been rendered, (iii) the customer's price is fixed or determinable and (iv) collectability is reasonably assured.

Revenues from compression services are recognized as earned under our fixed fee contracts. Compression services are billed monthly in advance of the service period and are recognized as deferred revenue on the balance sheet until earned.

Recent Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board, or FASB, issued new guidance requiring an entity to perform an analysis to determine whether the entity's variable interest gives it a controlling financial interest in a variable interest entity. This analysis identifies the primary beneficiary of a variable interest entity as the entity that has both the power to direct the activities that most significantly impact the variable interest entity's economic performance and the obligation to absorb losses or the right to receive benefits from the variable interest entity. The new guidance also requires additional disclosures about a company's involvement in variable interest entities and any significant changes in risk exposure due to that involvement. The new guidance is effective for fiscal years beginning after November 15, 2009. Our adoption of this new guidance on January 1, 2010 did not have a material impact on our consolidated financial statements.

In October 2009, FASB issued an update to existing guidance on revenue recognition for arrangements with multiple deliverables. This update addresses accounting for multiple-deliverable arrangements to enable vendors to account for deliverables separately. The guidance establishes a selling price hierarchy for determining the selling price of a deliverable. This update requires expanded disclosures for multiple deliverable revenue arrangements. The update is effective for us for revenue arrangements entered into or materially modified on or after January 1, 2011. Our adoption of this new guidance on January 1, 2011 did not have a material impact on our consolidated financial statements.

In January 2010, FASB issued Accounting Standards Update 2010-06, Improving Disclosures about Fair Value Measurements, or ASU 2010-06, which amends FASB ASC Topic 820, Fair Value Measurements and Disclosures. ASU 2010-06 requires reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair-value measurements and information about purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair-value measurements. ASU 2010-06 also clarifies existing fair-value measurement disclosure guidance about the level of disaggregation, inputs, and valuation techniques. We have evaluated ASU 2010-06 and determined that we are not currently impacted by the update.

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NATURAL GAS COMPRESSION INDUSTRY

Role of Natural Gas Compression

Natural gas compression is a mechanical process whereby natural gas is compressed to a smaller volume resulting in a higher pressure. In the U.S., there exists a complex system of pipelines, known as the natural gas grid, designed to transport natural gas from producing areas to markets. Because the grid is generally designed to move gas at increasing pressures, natural gas compression is required throughout all stages of the natural gas chain, including production at the wellhead; gathering, treating and processing; and transportation and storage.

Producing Regions (Wellhead). In general, wellhead compression is used to allow natural gas to flow from the wellhead into local gathering systems. There are several variables that impact compression requirements for wellhead applications, including, but not limited to, the natural pressure of the producing reservoir, initial flow rates of producing wells and the production decline rate over the life of the producing well. The variability in production characteristics over time results in frequently changing compression requirements, causing a need for regular modification and adjustment of on-site compression equipment. As a result, wellhead compression typically employs lower-horsepower, portable equipment located at or very near the wellhead. Given the shorter-life of a given well (and the related compression requirement), operators often outsource these compression requirements.

Central / Regional Gathering Systems. Gathering systems consist of networks of smaller-diameter pipelines that gather raw natural gas at the wellhead and transport it to central locations for processing, treating and connection with long-haul pipelines for further transportation. Compression is used along gathering systems to facilitate the movement of natural gas from the smaller-scale gathering systems, through central delivery points, and into larger-scale, higher volume regional gathering systems. While gathering systems vary depending on the particular producing region, size of the coverage area and other factors, large-horsepower compression units are generally required. As the gathering systems serve as a centralized transportation system for multiple wells, they tend to be more permanent in nature. Operators of regional gathering systems will both own and outsource their compression requirements depending on their needs.

Processing / Treating of Natural Gas. Natural gas used by consumers is composed almost entirely of methane. Natural gas when produced out of the earth is a mixture of hydrocarbons (principally methane, ethane, propane, butanes and pentanes), water vapor, hydrogen sulfide, carbon dioxide,

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helium, nitrogen and other compounds. At various points from the wellhead to the major transportation pipelines, the gas stream is purified to remove the non-methane components from the raw natural gas stream. Compression is often utilized in the various processes used to purify the natural gas stream, which includes processing to remove the various hydrocarbons and fluids, treating to remove sulfur and carbon dioxide and dehydration to remove water vapor. Processors of natural gas will both own and outsource their compression requirements depending on their needs.

Long-Haul Transportation and Storage. Natural gas is transported from regional gathering facilities and processing plants to local end-user markets by long-haul transmission pipelines. These transmission lines consist of large-scale pipelines operating at very high pressures in order to move large quantities of gas efficiently. Additionally, transmission lines have highly stable compression conditions that are maintained for long periods of time. The compression for long haul transportation is provided using very large horsepower compression units. Further, these units tend to be installed as permanent components of the pipeline, and are generally owned by the pipeline operators themselves.

Natural gas storage is primarily used to balance the relatively constant supply of natural gas with the more seasonal demand for natural gas. In natural gas storage operations, gas is injected into storage facilities, typically underground salt caverns or depleted hydrocarbon reservoirs, and stored until market demand dictates. Storage is also used to balance supply and demand between producing regions and consuming regions. Natural gas storage operations also require very large horsepower compression, resulting in the installation of permanent compression units typically owned by the storage operator.

Role of Compression Services in the Natural Gas Chain

As described above, each portion of the natural gas chain has distinct compression requirements and timeframes under which compression requirements change. These components are important factors in understanding whether producers, processors, gatherers and transporters of natural gas own compression equipment or seek to contract for compression services through providers such as us.

Natural Gas Chain Component	Pressure Requirement	Typical Unit Horsepower (HP)	Typical Facility Horsepower (HP)	Compression Conditions	Outsource / Own	Typical Contract Tenor
Wellhead	Low	<250	<250	Variable	Outsource / Own	Short-Term
Central Gathering	Low / Moderate	>250 <1,800	>250 <10,000	Moderately Stable	Outsource / Own	Medium / Long-Term
Regional Gathering	Moderate / High	>1,000 <5,000	>3,000 <50,000	Stable	Outsource / Own	Medium / Long-Term
Processing / Treating	Moderate / High	>1,000 <5,000	>3,000 <50,000	Stable	Outsource / Own	Medium / Long-Term
Long-Haul Pipelines / Storage	Very High	>2,500 <30,000	>10,000 <150,000	Very Stable / Constant	Typically Own	N/A

As compression conditions increase in variability, it becomes economic for a customer to outsource compression services. Outsourced compression services permit customers to meet their changing compression needs more efficiently over time while limiting their capital investments in compression equipment. Moreover, customers benefit from the specialized personnel, including engineers and field service employees, and technical skills that compression services providers offer.

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BUSINESS

Overview

We are a growth-oriented Delaware limited partnership and, based on management's significant experience in the industry, we believe that we are one of the largest independent providers of compression services in the U.S. in terms of total compression unit horsepower. As of September 30, 2012, we had 889,099 horsepower in our fleet and 31,630 horsepower on order for delivery, of which 23,135 horsepower has been delivered as of November 30, 2012 and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013. We employ a customer-focused business philosophy in partnering with our diverse customer base, which is comprised of producers, processors, gatherers and transporters of natural gas. Natural gas compression, a mechanical process whereby natural gas is compressed to a smaller volume, resulting in higher pressure, is an essential part of the production and transportation of natural gas. As part of our services, we engineer, design, operate, service and repair our compression units and maintain related support inventory and equipment. The compression units in our modern fleet are designed to be easily adaptable to fit our customers' dynamic compression requirements. By focusing on the needs of our customers and by providing them with reliable and flexible compression services, we are able to develop long-term relationships, which lead to more stable cash flows for our unitholders. From 2003 through the third quarter of 2012, our average horsepower utilization was over 90%. We have been providing compression services since 1998.

We focus primarily on large-horsepower infrastructure applications. As of September 30, 2012, we estimate that over 90% of our revenue generating horsepower was deployed in large-volume gathering systems, processing facilities and transportation applications. We operate a modern fleet, with an average age of our compression units of approximately five years. Our standard new-build compression unit is generally configured for multiple compression stages allowing us to operate our units across a broad range of operating conditions. This flexibility allows us to enter into longer-term contracts and reduces the redeployment risk of our horsepower in the field. Our modern and standardized fleet, decentralized field-level operating structure and technical proficiency in predictive and preventive maintenance and overhaul operations have enabled us to achieve average service run times consistently above the levels required by our customers.

We generally provide our compression services to our customers under long-term, fixed-fee contracts, with initial contract terms of up to five years. We typically continue to provide compression services to our customers beyond their initial contract terms, either through contract renewals or on a month-to-month basis. Our customers are typically required to pay our monthly fee even during periods of limited or disrupted natural gas flows, which enhances the stability and predictability of our cash flows. We are not directly exposed to natural gas price risk because we do not take title to the natural gas we compress and because the natural gas used as fuel by our compression units is supplied by our customers without cost to us.

We provide compression services in a number of shale plays, including the Fayetteville, Marcellus, Woodford, Barnett, Eagle Ford and Haynesville shales. We believe compression services for shale production will increase in the future. According to the Annual Energy Outlook 2013 Early Release prepared by the EIA, natural gas production from shale formations will increase from 34% of total U.S. natural gas production in 2011 to 50% of total U.S. natural gas production in 2040. Not only are the production and transportation volumes in these and other shale plays increasing, but the geological and reservoir characteristics of these shales are also particularly attractive for compression services. The changes in production volume and pressure of shale plays over time result in a wider range of compression requirements than in conventional basins. We believe we are well-positioned to meet these changing operating conditions as a result of the flexibility our compression units. While our business focus is largely compression serving shale plays, we also provide compression services in more mature conventional basins. These conventional basins require increasing amounts of compression as they age and pressures decline, which we believe will provide an additional source of stable and growing cash flows for our unitholders.

For the year ended December 31, 2011, our business generated revenues, net income and Adjusted EBITDA of $98.7 million, $0.1 million and $51.3 million, respectively. For the nine months ended September 30, 2012, our business generated revenues, net income and Adjusted EBITDA of $87.0 million, $3.6 million and $46.7 million, respectively. Please read " Non-GAAP Financial Measures" for an explanation of Adjusted EBITDA, which is a non-GAAP financial measure, and a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP.

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability and growth of our business. We expect to achieve this objective by executing on the following strategies:

- ***Capitalize on the increased need for natural gas compression in conventional and unconventional plays.*** We expect additional demand for compression services to result from the continuing shift of natural gas production to domestic shale plays as well as the declining production pressures of aging conventional basins. Our fleet of modern, flexible compression units, which are capable of being rapidly deployed and redeployed and many of which are designed to operate in multiple compression stages, will enable us to capitalize on opportunities both in these emerging shale plays as well as conventional fields.

- ***Continue to execute on attractive organic growth opportunities.*** Between 2003 and 2011, we grew the horsepower in our fleet of compression units at a compound annual growth rate of 23% and grew our compression revenues at a compound annual growth rate of 24%, primarily through organic growth. We believe organic growth opportunities will continue to be our most attractive source of near-term growth. We seek to achieve continued organic growth by (i) increasing our business with existing customers, (ii) obtaining new customers in our existing areas of operations and (iii) expanding our operations into new geographic areas.

- ***Partner with customers who have significant compression needs.*** We actively seek to identify customers with major acreage positions in active and growing areas. We work with these customers to jointly develop long-term and adaptable solutions designed to optimize their lifecycle compression costs. We believe this is important in determining the overall economics of producing, gathering and transporting natural gas. Our proactive and collaborative approach positions us to serve as our customers' compression provider of choice.

- ***Pursue accretive acquisition opportunities.*** While our principal growth strategy will be to continue to grow organically, we may pursue accretive acquisition opportunities, including the acquisition of complementary businesses, participation in joint ventures or purchase of compression units from existing or new customers in conjunction with providing compression services to them. We will consider opportunities that (i) are in our existing geographic areas of operations or new, high-growth regions, (ii) meet internally established economic thresholds and (iii) may be financed on reasonable terms.

- ***Maintain financial flexibility.*** We intend to maintain financial flexibility to be able to take advantage of growth opportunities. Historically, we have utilized our cash flow from operations, borrowings under available debt facilities and operating leases to fund capital expenditures to expand our compression services business. This approach has allowed us to significantly grow our fleet and the amount of cash we generate, while maintaining our debt at levels we believe are manageable for our business. Pro forma for this offering, we would have had $298.6 million in borrowing capacity available under our revolving credit facility as of September 30, 2012. We believe our financial flexibility positions us to take advantage of future growth opportunities without incurring debt beyond appropriate levels.

Competitive Strengths

We believe that we are well positioned to successfully execute our business strategies and achieve our principal business objective because of the following competitive strengths:

Stable and growing fee-based cash flows. We charge our customers a fixed monthly fee for our compression services, regardless of the volume of natural gas we compress in that month. Our contracts have initial terms of up to five years and typically extend beyond their initial contract terms, either through contract renewals or on a month-to-month basis. We believe the long-term nature of our fixed-fee contracts enhances our ability to generate stable cash flows and mitigates our exposure to short-term volatility in natural gas and crude oil commodity prices. Our focus on large-horsepower compression associated with large-volume gathering and transportation-related applications also mitigates our exposure to the higher volatility associated with smaller wellhead applications.

Modern and efficient large-horsepower compression fleet with multi-stage compression capabilities that can be rapidly and efficiently deployed or relocated. We maintain and utilize a modern, flexible and reliable fleet of compression units to provide compression services. As of September 30, 2012, approximately 84% of our fleet by horsepower (including compression units on order) was comprised of units with greater than 500 horsepower. Our compression units are built on a standardized equipment package and have an average age of approximately five years. Approximately 69% of our fleet horsepower as of September 30, 2012 was comprised of convertible multi-stage compression units. The flexible configuration of our units enables us to quickly and effectively adapt to changing field conditions, allowing us to render our compression services across a broad range of operating conditions without the need to replace equipment. This adaptability results in lower downtime and operating costs for our customers, generally allowing us to obtain longer-term contracts and provide our compression services more efficiently within fields and across geographies.

Long-standing and strategic customer relationships. We have developed long-standing and strategic customer relationships by consistently delivering outstanding service run time and superior service, and by effectively adapting to our customers' specific and continually changing compression needs. Our top ten customers for the year ended December 31, 2011 accounted for 53% of our revenues and have contracted compression services from us for an average of nine years. Of these all have been customers for at least six years and six have been customers for over ten years. These relationships provide a strong platform for continued organic growth as we respond to our customers' increasing and dynamic natural gas compression needs.

Broad geographic presence in key domestic markets. Our primary business focus is providing compression services in high-growth shale plays where typically steep declines in production volumes and changes in production pressures require significant compression. We also provide compression services in more mature conventional basins that will require increasing amounts of compression as these fields age and pressures decline.

Experienced management team with a proven ability to deliver strong organic growth. Our Chief Executive Officer, Eric D. Long, co-founded our company and has over 20 years of experience in the compression industry. The members of our management team have an average of over 25 years of experience in energy and service industries, and several key executive members of our sales and operating team have worked together for over 14 years. Our organic growth has resulted from our management's commitment to optimize compression lifecycle cost for our customers by delivering outstanding customer service.

Supportive sponsor with significant industry expertise. Riverstone is the principal owner of our general partner. Riverstone has substantial experience as a private equity investor in master limited partnerships, with current or prior investments in the general partners or managing members of Buckeye Partners, L.P., Kinder Morgan Energy Partners, L.P., Magellan Midstream Partners, L.P. and Niska Gas Storage Partners LLC. Riverstone's management has substantial experience in identifying, evaluating, negotiating and financing acquisitions and investments. By providing us with strategic guidance and financial expertise, we believe our relationship with Riverstone will greatly enhance our ability to grow our asset base and cash flow.

Our Operations

Compression Services

We provide compression services for a monthly service fee. As part of our services, we engineer, design, operate, service and repair our fleet of compression units and maintain related support inventory and equipment. We have consistently provided average service run times above the levels required by our customers. In general, our team of field service technicians service our compression fleet and do not service third-party owned equipment. We do not rent or lease our compressors to our customers and do not own any compression fabrication facilities.

Our Compression Fleet

The fleet of compression units that we own and use to provide compression services consists of specially engineered compression units that utilize standardized components, principally engines manufactured by Caterpillar, Inc. and compressor frames and cylinders manufactured by Ariel Corporation. Our units can be rapidly and cost effectively modified for specific customer applications. Approximately 95% of our fleet horsepower at September 30, 2012 was purchased new and the average age of our compression units is approximately five years. Our modern, standardized compressor fleet mainly consists of the Caterpillar 3508, 3512 and 3516 engine classes, which range from 630 to 1,340 horsepower per unit, and we are expanding our fleet to include the Caterpillar 3606 and 3608 engine class, which range from 1,775 to 2,352 horsepower per unit. These larger units, defined as 500 horsepower per unit or greater, represented approximately 84% of our fleet (including compression units on order) as of September 30, 2012. We believe the young age and overall composition of our compressor fleet results in fewer mechanical failures, lower fuel usage (a direct cost savings for our customers), and reduced environmental emissions.

The following table provides a summary of our compression units by horsepower as of September 30, 2012 (including additional new compression unit horsepower on order for delivery between October 2012 and December 2012):

Unit Horsepower	Fleet Horsepower	Horsepower on Order(1)	Total Horsepower(2)	Percentage of Total Horsepower
<500	141,354	2,250	143,604	15.6%
>500 <1,000	114,540	1,380	115,920	12.6%
>1,000	633,205	28,000	661,205	71.8%
Total	889,099	31,630	920,729	100.0%

(1) As of November 30, 2012, 23,135 horsepower has been delivered and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013.

(2) Comprised of 1,175 compression units, including 26 new compression units on order.

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The following table sets forth certain information regarding our compression fleet as of the dates and for the periods indicated:

	Predecessor				Successor	
	Year Ended December 31,				Year Ended December 31,	Nine Months Ended September 30,
	2007	2008	2009	2010	2011	2012
Operating Data (at period end, except averages) unaudited						
Fleet horsepower(1)	453,508	542,899	582,530	609,730	722,201	889,099
Total available horsepower(2)	476,698	568,359	582,530	612,410	809,418	902,164
Revenue generating horsepower(3)	405,807	496,606	502,177	533,692	649,285	786,750
Average revenue generating horsepower(4)	370,826	455,673	489,243	516,703	570,900	735,639
Revenue generating compression units	613	763	749	795	888	964
Average horsepower per revenue generating compression unit(5)	665	651	655	667	692	784
Horsepower utilization(6)						
At period end	93.7%	95.2%	92.0%	91.8%	95.7%	93.4%
Average for the period(7)	93.9%	95.9%	92.7%	92.6%	92.3%	95.0%

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of September 30, 2012, we had 31,630 of additional new compression unit horsepower on order, of which 23,135 horsepower has been delivered as of November 30, 2012 and 8,495 horsepower is expected to be delivered in December 2012. In October 2012, we ordered 35,880 of additional horsepower which is expected to be delivered between January 2013 and April 2013. In December 2012, we ordered 50,915 of additional horsepower which is expected to be delivered between April 2013 and July 2013.

(2) Total available horsepower includes revenue generating horsepower under contract for which we are billing a customer, horsepower in our fleet that is under contract but is not yet generating revenue, horsepower not yet in our fleet that is under contract not yet generating revenue that is subject to a purchase order and idle horsepower. Total available horsepower excludes new horsepower on order for which we do not have a compression services contract.

(3) Revenue generating horsepower is horsepower under contract for which we are billing a customer.

(4) Calculated as the average of the month-end revenue generating horsepower for each of the months in the period.

(5) Calculated as the average of the month-end horsepower per revenue generating compression unit for each of the months in the period.

(6) Horsepower utilization is calculated as (i)(a) revenue generating horsepower plus (b) horsepower in our fleet that is under contract, but is not yet generating revenue plus (c) horsepower not yet in our fleet that is under contract not yet generating revenue and will be fulfilled by horsepower subject to a purchase order divided by (ii) total available horsepower less idle horsepower that is under repair.

Horsepower utilization based on revenue generating horsepower and fleet horsepower at each applicable period end was 89.5%, 91.5%, 86.2%, 87.5% and 89.9% for the years ended December 31, 2007, 2008, 2009, 2010 and 2011, respectively, and 85.5% and 88.5% for the nine months ended September 30, 2011 and 2012, respectively.

(7)
Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period.

A substantial majority of our compression units have electronic control systems that enable us, if specified by our customers, to monitor our units remotely by satellite or other means to supplement our technicians' on-site monitoring visits. Our compression units are designed to automatically shut down if operating conditions deviate from a pre-determined range. While we retain the care, custody, ongoing maintenance and control of our compression units, we allow our customers, subject to a defined protocol, to start, stop, accelerate and slow down compression units in response to field conditions.

We adhere to routine, preventive and scheduled maintenance cycles. Each of our compression units is subjected to rigorous sizing and diagnostic analyses, including lubricating oil analysis and engine exhaust emission analysis. We have proprietary field service automation capabilities that allow our service technicians to electronically record and track operating, technical, environmental and commercial information at the discrete unit level. These capabilities allow our field technicians to identify potential problems and act on them before such problems result in downtime.

Generally, we expect each of our compression units to undergo a major overhaul between service deployment cycles once every eight to ten years for our larger horsepower units (500 horsepower or more) and on average every five years for smaller horsepower units. A major overhaul involves the periodic rebuilding of the unit to materially extend its economic useful life or to enhance the unit's ability to fulfill broader or more diversified compression applications. Because our compression fleet is comprised of units of varying horsepower that have been placed into service with staggered initial on-line dates, we expect that we will be able to schedule overhauls in a way to avoid excessive maintenance capital expenditures and minimize the revenue impact of downtime.

We believe that our customers, by outsourcing their compression requirements, can increase their revenue by transporting or producing a higher volume of natural gas through decreased compression downtime and reduce their operating, maintenance and equipment costs by allowing us to manage efficiently their changing compression needs. We generally guarantee our customers availability ranging from 95% to 98%, depending on field level requirements.

General Compression Service Contract Terms

The following discussion describes the material terms generally common to our compression service contracts. We generally enter into a new contract with respect to each distinct application for which we will provide compression services.

Term and termination. Our contracts typically have an initial term between one and five years, after which the contract continues on a month-to-month basis until terminated by us or our customers upon notice as provided for in the applicable contract.

Availability. Our contracts often provide a guarantee of specified availability. We define availability as the percentage of time in a given period that our compression services are being provided or are capable of being provided. Availability is reduced by instances of "down-time" that are attributable to anything other than events of *force majeure* or acts or failures to act by the customer. "Down-time" under our contracts usually begins when our services stop being provided and when we receive notice of the problem. Down-time due to scheduled maintenance is also excluded from our availability commitment. As a consequence of our availability guarantee, we are incentivized to practice predictive and preventive maintenance on our fleet as well as promptly respond to a problem to meet our contractual commitments and ensure our customers the compression availability on which their business and our service relationship is based.

Fees and expenses. Our customers pay a fixed monthly fee for our services. We bill our customers 30 days in advance, and they are required to pay upon receipt of the invoice. We are not responsible for acts of *force majeure*, and our customers generally are required to pay our monthly fee even during periods of limited or disrupted throughput. We are generally responsible for the costs and expenses associated with operation and maintenance of our compression equipment, such as providing necessary lubricants, although certain fees and expenses are the responsibility of our customers under the terms

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of their contracts. For example, all fuel gas is provided by our customers without cost to us, and in many cases customers are required to provide all water and electricity, while lubricants in certain cases may be provided by the customer. We are also reimbursed by our customers for certain ancillary expenses such as trucking and crane, depending on the terms agreed to in the applicable contract, resulting in no gross operating margin.

Service standards and specifications. We commit to provide compression services under service contracts that typically provide that we will supply all compression equipment, tools, parts, field service support and engineering. Our contracts do not govern the compression equipment we will use; instead, we determine what equipment is necessary to perform our contractual commitments.

Title; Risk of loss. We own or lease all compression equipment we use to provide compression services, and we normally bear the risk of loss or damage to our equipment and tools and injury or death to our personnel.

Insurance. Our contracts typically provide that both we and our customers are required to carry general liability, worker's compensation, employers' liability, automobile and excess liability insurance.

Marketing and Sales

Our marketing and client service functions are performed on a coordinated basis by our sales and field technicians. Salespeople and field technicians qualify, analyze and scope new compression applications as well as regularly visit our customers to ensure customer satisfaction, to determine a customer's current needs related to services currently being provided and to determine the customer's future compression services requirements. This ongoing communication allows us to quickly identify and respond to our customers' compression requirements. We currently focus on geographic areas where we can achieve economies of scale through high density operations.

Customers

Our customers consist of more than 110 companies in the energy industry, including major integrated oil companies, public and private independent exploration and production companies and midstream companies. Our largest customer for the year ended December 31, 2011 and nine months ended September 30, 2012 was Southwestern Energy. Southwestern Energy accounted for 15.9% of our revenue for the year ended December 31, 2011 and 14.3% of our revenues for the nine months ended September 30, 2012. Our ten largest customers accounted for 53% and 54% of our revenues for the year ended December 31, 2011 and for the nine months ended September 30, 2012, respectively.

Suppliers and Service Providers

The principal manufacturers of components for our natural gas compression equipment include Caterpillar (for engines), Air-X-Changers and Air Cooled Exchangers (for coolers), and Ariel Corporation (for compressor frames and cylinders). We also rely primarily on two vendors, A G Equipment Company and Standard Equipment Corp., to package and assemble our compression units. Although we rely primarily on these suppliers, we believe alternative sources for natural gas compression equipment are generally available if needed. However, relying on alternative sources may change the standardized nature of our fleet. We have not experienced any material supply problems to date, although lead-times for Caterpillar engines have in the past been in excess of one year due to increased demand and supply allocations imposed on equipment packagers and end-users by Caterpillar.

Competition

The compression services business is highly competitive. Some of our competitors have a broader geographic scope, as well as greater financial and other resources than we do. On a regional basis, we experience competition from numerous smaller companies that may be able to more quickly adapt to changes within our industry and changes in economic conditions as a whole, more readily take advantage of available opportunities and adopt more aggressive pricing policies. Additionally, the current availability of attractive financing terms from financial institutions and equipment manufacturers makes the purchase of individual compression units increasingly affordable to our customers. We believe that we compete effectively on the basis of price, equipment availability, customer service, flexibility in meeting customer needs, quality and reliability of our compressors and related services.

Seasonality

Our results of operations have not historically reflected any material seasonality, and we do not currently have reason to believe seasonal fluctuations will have a material impact in the foreseeable future.

Insurance

We believe that our insurance coverage is customary for the industry and adequate for our business. As is customary in the natural gas services industry, we review our safety equipment and procedures and carry insurance against most, but not all, risks of our business. Losses and liabilities not covered by insurance would increase our costs. The compression business can be hazardous, involving unforeseen circumstances such as uncontrollable flows of gas or well fluids, fires and explosions or environmental damage. To address the hazards inherent in our business, we maintain insurance coverage that includes physical damage coverage, third-party general liability insurance, employer's liability, environmental and pollution and other coverage, although coverage for environmental and pollution-related losses is subject to significant limitations. Under the terms of our standard compression services contract, we are responsible for the maintenance of insurance coverage on our compression equipment.

Environmental and Safety Regulations

We are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health, safety and the environment. These regulations include compliance obligations for air emissions, water quality, wastewater discharges and solid and hazardous waste disposal, as well as regulations designed for the protection of human health and safety and threatened or endangered species. Compliance with these environmental laws and regulations may expose us to significant costs and liabilities and cause us to incur significant capital expenditures in our operations. We are often obligated to obtain permits or approvals in our operations from various federal, state and local authorities, which permits and approvals can be denied or delayed, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue. Moreover, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial obligations, and the issuance of injunctions delaying or prohibiting operations. Private parties may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. While we believe that our operations are in substantial compliance with applicable environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this trend of compliance will continue in the future. In addition, the clear trend in environmental regulation is to place more restrictions on activities that may affect the environment, and thus, any changes in, or more stringent enforcement of, these laws and regulations that result in more stringent and costly pollution control equipment, waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. We cannot assure you, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. The following is a discussion of material environmental and safety laws that relate to our operations. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Air emissions. The CAA and comparable state laws regulate emissions of air pollutants from various industrial sources, including natural gas compressors, and also impose certain monitoring and reporting requirements. Such emissions are regulated by air emissions permits, which are applied for and obtained through the various state or federal regulatory agencies. Our standard natural gas compression contract typically provides that the customer is responsible for obtaining air emissions permits and assuming the environmental risks related to site operations. Increased obligations of operators to reduce air emissions of nitrogen oxides and other pollutants from internal combustion engines in transmission service have been enacted by governmental authorities. For example, on August 20, 2010, the EPA published new regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines, also known as Quad Z regulations. On May 22, 2012, the EPA proposed amendments to the final rule in response to several petitions for reconsideration. The EPA must finalize the proposed amendments by January 14, 2013. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment on certain compressor engines and generators. Compliance with the final rule is required by October 2013. We are currently evaluating the impact that the proposed amendments will have on our operations but we do not believe that the costs associated with achieving compliance with the final rule and proposed amendments by the October 2013 compliance date will be material.

On June 28, 2011, the EPA issued a final rule, effective August 29, 2011 modifying existing regulations under the CAA that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines, also known as Quad J regulations. The final rule may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment. Compliance with the final rule is not required until at least 2013. On May 22, 2012, the EPA proposed minor amendments in order to conform the final rule with the proposed amendments to the Quad Z regulations. The amendments must be finalized by January 14, 2013. We are currently evaluating the impact that this final rule and proposed amendments will have on our operations.

In March 2008, the EPA also promulgated a new, lower National Ambient Air Quality Standard, or NAAQS, for ground-level ozone, or NOx. While the EPA announced in September 2009 that it would reconsider the 2008 NAAQS for NOx, it withdrew the reconsideration on September 2, 2011. Under the CAA, the EPA will be required to review and potentially issue a new NAAQS for ground level NOx in 2013. Designation of new non-attainment areas for the revised ozone and NOx NAAQS may result in additional federal and state regulatory actions that could impact our customers' operations and increase the cost of additions to property, plant and equipment.

On April 17, 2012, the EPA finalized rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants at 500 ppm. These rules

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may require a number of modifications to our operations, including the installation of new equipment to control emissions from our compressors at initial startup, or October 15, 2012, whichever is later. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, the Texas Commission on Environmental Quality, or TCEQ, has finalized revisions to certain air permit programs that significantly increase the air permitting requirements for new and certain existing oil and gas production and gathering sites for 23 counties in the Barnett Shale production area. The final rule establishes new emissions standards for engines, which could impact the operation of specific categories of engines by requiring the use of alternative engines, compressor packages or the installation of aftermarket emissions control equipment. The rule became effective for the Barnett Shale production area in April 2011, with the lower emissions standards becoming applicable between 2015 and 2030 depending on the type of engine and the permitting requirements. The cost to comply with the revised air permit programs is not expected to be material at this time. However, the TCEQ has stated it will consider expanding application of the new air permit program statewide. At this point, we cannot predict the cost to comply with such requirements if the geographic scope is expanded.

There can be no assurance that future requirements compelling the installation of more sophisticated emission control equipment would not have a material adverse impact.

Climate change. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases, or GHGs. In recent years, the U.S. Congress has considered legislation to reduce emissions of GHGs. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. In addition, almost half of the states have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Depending on the particular program, we could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

Independent of Congress, the U.S. Environmental Protection Agency, or the EPA, is beginning to adopt regulations controlling GHG emissions under its existing Clean Air Act authority. For example, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large GHG emission sources. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of GHG emissions by such regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. In 2010, the EPA also issued a final rule, known as the "Tailoring Rule," that makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. Several of the EPA's GHG rules are being challenged in court and, depending on the outcome of these proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Although it is not currently possible to predict how any such proposed or future greenhouse gas legislation or regulation by Congress, the states or multi-state regions will impact our business, any

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legislation or regulation of greenhouse gas emissions that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions or reduced demand for our services, and could have a material adverse effect on our business, financial condition, and results of operations.

Water discharge. The Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. The CWA also requires the development and implementation of spill prevention, control, and countermeasures, including the construction and maintenance of containment berms and similar structures, if required, to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak at such facilities. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. Our compression operations do not generate process wastewaters that are discharged to waters of the U.S. In any event, our customers assume responsibility under our standard natural gas compression contract for obtaining any discharge permits that may be required under the CWA.

Safe Drinking Water Act. A portion of our customers' natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in 2014. EPA also has recently announced that it believes hydraulic fracturing using fluids containing diesel fuel can be regulated under the SDWA notwithstanding the SDWA's general exemption for hydraulic fracturing. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. We cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce demand for our compression services, which would materially adversely affect our revenue and results of operations.

Solid waste. The Resource Conservation and Recovery Act, or the RCRA, and comparable state laws control the management and disposal of hazardous and non-hazardous waste. These laws and regulations govern the generation, storage, treatment, transfer and disposal of wastes that we generate including, but not limited to, used oil, antifreeze, filters, sludges, paint, solvents, and sandblast materials. The EPA and various state agencies have limited the approved methods of disposal for these types of wastes.

Site remediation. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, and comparable state laws impose strict, joint and several liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to the release of a

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hazardous substance into the environment. These persons include the owner and operator of a disposal site where a hazardous substance release occurred and any company that transported, disposed of, or arranged for the transport or disposal of hazardous substances released at the site. Under CERCLA, such persons may be liable for the costs of remediating the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, where contamination may be present, it is not uncommon for the neighboring landowners and other third parties to file claims for personal injury, property damage and recovery of response costs. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA at any site.

While we do not currently own or lease any material facilities or properties for storage or maintenance of our inactive compression units, we may use third-party properties for such storage and possible maintenance and repair activities. In addition, our active compression units typically are placed on properties owned or leased by third-party customers and operated by us pursuant to terms set forth in the natural gas compression services contracts executed by those customers. Under most of our natural gas compression services contracts, our customers must contractually indemnify us for certain damages we may suffer as a result of the release into the environment of hazardous and toxic substances. We are not currently responsible for any remedial activities at any properties used by us; however, there is always the possibility that our future use of those properties may result in spills or releases of petroleum hydrocarbons, wastes, or other regulated substances into the environment that may cause us to become subject to remediation costs and liabilities under CERCLA, RCRA or other environmental laws. We cannot provide any assurance that the costs and liabilities associated with the future imposition of such remedial obligations upon us would not have a material adverse effect on our operations or financial position.

Safety and health. The Occupational Safety and Health Act, or OSHA, and comparable state laws strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and, as necessary, disclose information about hazardous materials used or produced in our operations to various federal, state and local agencies, as well as employees.

Properties

We do not currently own or lease any material facilities or properties for storage or maintenance of our compression units. Our headquarters consists of 3,065 square feet of leased space located at 100 Congress Avenue, Suite 450, Austin, Texas 78701.

Employees

We will be managed and operated by the officers and directors of USA Compression GP, our general partner. As of September 30, 2012, we employed 227 people either directly or through USAC Operating. None of our employees are subject to collective bargaining agreements. We consider our employee relations to be good.

Legal Proceedings

From time to time we may be involved in litigation relating to claims arising out of our operations in the normal course of business. We are not currently a party to any legal proceedings that we believe would have a material adverse effect on our financial position, results of operations or cash flows.

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MANAGEMENT OF USA COMPRESSION PARTNERS, LP

Our general partner, USA Compression GP, LLC, will manage our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. As described in the Second Amended and Restated Limited Liability Company Agreement of USA Compression GP, LLC, or the GP Agreement, USA Compression GP, LLC will be member-managed. The sole member has delegated to the board of directors all power and authority related to management of the partnership to the fullest extent permitted by law and the GP Agreement. The GP Agreement provides that there shall be at least two and no more than nine directors, who will oversee our operations. The board of directors will elect one or more officers who will serve at the pleasure of the board. Unitholders will not be entitled to elect the directors of USA Compression GP, LLC or directly or indirectly participate in our management or operation.

Upon the closing of this offering, the board of directors of our general partner will initially be comprised of six members, all of whom will be designated by USA Compression Holdings and one of whom will be independent as defined under the independence standards established by the New York Stock Exchange. In compliance with the rules of the NYSE, a second independent director will be appointed to the board of directors of USA Compression GP, LLC within 90 days of listing and a third independent director will be appointed within twelve months of listing. The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.

As set forth in the GP Agreement, USA Compression GP, LLC may, from time to time, have a conflicts committee to which the board of directors will appoint independent directors and which may be asked to review specific matters that the board believes may involve conflicts of interest between us, our limited partners and USA Compression Holdings. The conflicts committee will determine the resolution of the conflict of interest in any manner referred to it in good faith. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, including USA Compression Holdings, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. For a detailed discussion of the potential conflicts of interest we face and how they will be resolved, see "Conflicts of Interest and Fiduciary Duties Conflicts of Interest."

In addition, USA Compression GP, LLC will have an audit committee comprised of directors who meet the independence and experience standards established by the NYSE and the Exchange Act. The audit committee will assist the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee will have the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee.

Any person who is or was a member, partner, director, officer, affiliate, fiduciary or trustee of USA Compression GP, LLC, any person who is or was serving at the request of USA Compression GP, LLC or any affiliate of USA Compression GP, LLC as an officer, director, member, manager, partner, fiduciary or trustee of another person is entitled to indemnification under the GP Agreement for actions associated with such roles to the fullest extent permitted by law and the GP Agreement. The GP Agreement may be amended or restated at any time by the sole member.

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Directors and Executive Officers

The following table shows information regarding the current directors and executive officers of USA Compression GP, LLC.

Name	Age	Position with USA Compression GP, LLC
Eric D. Long	54	President and Chief Executive Officer and Director
Joseph C. Tusa, Jr.	54	Vice President, Chief Financial Officer and Treasurer
J. Gregory Holloway	55	Vice President, General Counsel and Secretary
David A. Smith	50	Vice President and President, Northeast Region
Dennis J. Moody	55	Vice President Operations Services
Kevin M. Bourbonnais	46	Vice President and Chief Operating Officer
Jim H. Derryberry	67	Director
Robert F. End	57	Director
William H. Shea, Jr.	57	Director
Andrew W. Ward	45	Director
Olivia C. Wassenaar	33	Director

The directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of the directors or executive officers of our general partner.

Eric D. Long has served as our President and Chief Executive Officer since September 2002 and has served as a director of USA Compression GP, LLC since June 2011. Mr. Long co-founded USA Compression in 1998 and has over 30 years of experience in the oil and gas industry. From 1980 to 1987, Mr. Long served in a variety of technical and managerial roles for several major pipeline and oil and natural gas producing companies, including Bass Enterprises Production Co. and Texas Oil & Gas. Mr. Long then served in a variety of senior officer level operating positions with affiliates of Hanover Energy, Inc., a company primarily engaged in the business of gathering, compressing and transporting natural gas. In 1993, Mr. Long co-founded Global Compression Services, Inc., a compression services company. Mr. Long was formerly on the board of directors of the Wiser Oil Company, an NYSE listed company from May 2001 until it was sold to Forest Oil Corporation in May 2004. Mr. Long received his bachelor's degree, with honors, in Petroleum Engineering from Texas A&M University. He is a registered Professional Engineer in the state of Texas.

As a result of his professional background, Mr. Long brings to us executive-level strategic, operational and financial skills. These skills, combined with his over 30 years of experience in the oil and natural gas industry, including in particular his experience in the compression services sector, make Mr. Long a valuable member of our board.

Joseph C. Tusa, Jr. has served as our Vice President and Chief Financial Officer since joining us in January 2008. Mr. Tusa began his career with Arthur Andersen in Houston, Texas in its oil and gas exploration and production division. He then served as Chief Financial Officer of DSM Copolymer, Inc., a producer and global supplier of synthetic rubber. From 1997 to 2001, Mr. Tusa served as Senior Vice President of Business Operations for Metamor Worldwide, Inc., an IT services company that was listed on the NASDAQ exchange. From 2001 to December 2007, Mr. Tusa served as the Chief Financial Officer of Comsys IT Partners, Inc., an information technology staffing company and an affiliate of Metamor. Mr. Tusa received his BBA from Texas State University and his MBA from Louisiana State University. He is licensed as a Certified Public Accountant in the state of Texas.

J. Gregory Holloway has served as our Vice President, General Counsel and Secretary since joining us in June 2011. From September 2005 through June 2011, Mr. Holloway was a partner at Thompson & Knight LLP in its Austin office. His areas of practice at the firm included corporate,

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securities and merger and acquisition law. Mr. Holloway received his B.A. from Rice University and his J.D., with honors, from the University of Texas School of Law.

David A. Smith has served as our President, Northeast Region since joining us in November 1998 and was appointed corporate Vice President in June 2011. Mr. Smith has approximately 20 years of experience in the natural gas compression industry, primarily in operations and sales. From 1985 to 1989, Mr. Smith was a sales manager for McKenzie Corporation, a marketing company. From 1989 to 1996, Mr. Smith held positions of General Manager and Regional Manager of Northeast Division with Compressor Systems Inc., a fabricator and supplier of compression services. Mr. Smith was the Regional Manager in the northeast for Global Compression Services, Inc., a compression services company, and served in that capacity from 1996 to 1998. Mr. Smith received an associates degree in Automotive and Diesel Technology from Rosedale Technical Institute.

Dennis J. Moody has served as our Vice President Operations Services since December 2011, as our General Manager, Central Region since December 2007 and previously served as sales manager since February 2002. Prior to this time, Mr. Moody served in positions of increasing responsibility since joining us in July 1999. Mr. Moody has over 30 years of experience with the operation, repair, sizing and sales of motor and electric driven compression equipment. From 1976 to 1979, Mr. Moody worked as an operator and repair mechanic and served on the overhaul crew at Mustang Fuel Corporation, an oil and gas company engaged in production, gathering, processing and marketing of natural gas. From 1979 to 1984, Mr. Moody managed the service, repair and parts distribution facilities for the drilling and industrial air compression distributors of Ingersoll-Rand and Sullair brand compressors in Oklahoma. From 1984 to July 1999, Mr. Moody served in an industrial and gas compression sales and sales support role at Bush Compression Industries, a fabricator of compression equipment.

Kevin M. Bourbonnais has served as our Vice President and Chief Operating Officer since June 2011. Mr. Bourbonnais has approximately 13 years of experience in the natural gas compression industry, in operations, marketing, manufacturing, engineering and sales. Mr. Bourbonnais served in various roles for the Royal Bank of Canada from 1990 to 1999. In 1999, he moved to Weatherford Global Compression, which was acquired by a predecessor to Exterran Holdings, Inc. in 2001. Mr. Bourbonnais was named Senior Vice President, Manufacturing in 2003, Senior Vice President, Operations in March 2007, Regional Vice President, Western Division in August 2007 and Vice President, Marketing & Product Strategy in January 2010, in which role he served until June 2011. Mr. Bourbonnais received a BA and an MBA from the University of Calgary in 1989 and 2000, respectively.

Jim H. Derryberry has served as a director of USA Compression GP, LLC since January 2013. From February 2005 to October 2006, Mr. Derryberry served on the board of directors of Magellan GP, LLC, the general partner of Magellan Midstream Partners, L.P. Mr. Derryberry served as chief operating officer and chief financial officer of Riverstone Holdings, LLC until 2006 and currently serves as a special advisor. Prior to joining Riverstone, Mr. Derryberry was a managing director of J.P. Morgan, where he served as head of the Natural Resources and Power Group. Before joining J.P. Morgan, Mr. Derryberry was in the Goldman Sachs Global Energy and Power Group where he was responsible for mergers and acquisitions, capital markets financing and the management of relationships with major energy companies. He has also served as an advisor to the Russian government for energy privatization. Mr. Derryberry has served as a member of the Board of Overseers for the Hoover Institution at Stanford University and is a member of the Engineering Advisory Board at the University of Texas at Austin. He received his B.S. and M.S. degrees in engineering from the University of Texas at Austin and earned an M.B.A. from Stanford University.

Mr. Derryberry brings significant knowledge and expertise to our board from his service on other boards and his years of experience in our industry including his useful insight into investments and proven leadership skills as a managing director of Riverstone Holdings, LLC. As a result of his experience and skills, we believe Mr. Derryberry is a valuable member of our board.

Robert F. End has served as a director of USA Compression GP, LLC since November 2012. Mr. End served as a director of Hertz Global Holdings, Inc. from December 2005 until August 2011. Mr. End was a Managing Director of Transportation Resource Partners, or TRP, a private equity firm from 2009 through 2011. Prior to joining TRP in 2009, Mr. End had been a Managing Director of Merrill Lynch Global Private Equity Division, or MLGPE, the private equity arm of Merrill Lynch & Co., Inc., where he served as Co-Head of the North American Region, and a Managing Director of Merrill Lynch Global Private Equity, Inc., the Manager of ML Global Private Equity Fund, L.P., a proprietary private equity fund which he joined in 2004. Previously, Mr. End was a founding Partner and Director of Stonington Partners Inc., a private equity firm established in 1994. Prior to leaving Merrill Lynch in 1994, Mr. End was a Managing Director of Merrill Lynch Capital Partners, Merrill Lynch's private equity group. Mr. End joined Merrill Lynch in 1986 and worked in the Investment Banking Division before joining the private equity group in 1989. Mr. End received his AB from Dartmouth College and his MBA from the Tuck School of Business Administration at Dartmouth College.

Mr. End brings significant knowledge and expertise to our board from his service on other boards and his years of experience with private equity groups, including his useful insight into investments and business development and proven leadership skills as Managing Director of MLGPE. As a result of this experience and resulting skills set, we believe Mr. End is a valuable member of our board.

William H. Shea, Jr. has served as a director of USA Compression GP, LLC since June 2011. Mr. Shea served as the President and Chief Operating Officer of Buckeye GP LLC and its predecessor entities, or Buckeye, from July 1998 to September 2000, as President and Chief Executive Officer of Buckeye from September 2000 to July 2007, and Chairman from May 2004 to July 2007. From August 2006 to July 2007, Mr. Shea served as Chairman of MainLine Management LLC, the general partner of Buckeye GP Holdings, L.P., and as President and Chief Executive Officer of MainLine Management LLC from May 2004 to July 2007. Mr. Shea served as a director of Penn Virginia Corp. from July 2007 to May 2010, and as President, Chief Executive Officer and director of the general partner of Penn Virginia GP Holdings, L.P. from March 2010 to March 2011. Mr. Shea has served as a director and the Chief Executive Officer of the general partner of Penn Virginia Resource Partners, L.P., or Penn Virginia, since March 2010. Mr. Shea has also served as a director of Kayne Anderson Energy Total Return Fund, Inc., and Kayne Anderson MLP Investment Company since March 2008 and Niska Gas Storage Partners LLC since May 2010. Mr. Shea has an agreement with Riverstone, pursuant to which he has agreed to serve on the boards of certain Riverstone portfolio companies. Mr. Shea received his B.A. from Boston College and his M.B.A. from the University of Virginia.

Mr. Shea's experiences as an executive with both Penn Virginia and Buckeye, energy companies that operate across a broad spectrum of sectors, including coal, natural gas gathering and processing and refined petroleum products transportation, have given him substantial knowledge about our industry. In addition, Mr. Shea has substantial experience overseeing the strategy and operations of publicly-traded partnerships. As a result of this experience and resulting skills set, we believe Mr. Shea is a valuable member of our board.

Andrew W. Ward has served as a director of USA Compression GP, LLC since June 2011. Mr. Ward has served as a Principal of Riverstone from 2002 until 2004, as a Managing Director since January 2005 and as a Partner and Managing Director since July 2009, where he focuses on the firm's investment in the midstream sector of the energy industry. Mr. Ward served on the boards of directors of Buckeye and MainLine Management LLC from May 2004 to June 2006. Mr. Ward has also served on the board of directors of Gibson Energy Inc. since 2008 and Niska Gas Storage Partners LLC since

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May 2006. Mr. Ward received his AB from Dartmouth College and received his M.B.A from the UCLA Anderson School of Management.

Mr. Ward's experience in evaluating the financial performance and operations of companies in our industry make him a valuable member of our board. In addition, Mr. Ward's work with Gibson Energy, Inc., Buckeye and Niska Gas Storage Partners LLC has given him both an understanding of the midstream sector of the energy business and of the unique issues related to operating publicly-traded limited partnerships.

Olivia C. Wassenaar has served as a director of USA Compression GP, LLC since June 2011. Ms. Wassenaar was an Associate with Goldman, Sachs & Co. in the Global Natural Resources investment banking group from July 2007 to August 2008, where she focused on mergers, equity and debt financings and leveraged buyouts for energy, power and renewable energy companies. Ms. Wassenaar joined Riverstone in September 2008 as Vice President, and has served as a Principal since May 2010. In this capacity, she invests in and monitors investments in the midstream, exploration & production, and solar sectors of the energy industry. Ms. Wassenaar has also served on the board of directors of Northern Blizzard Resources Inc. since June 2011 and on the board of directors of Talos Energy LLC. Ms. Wassenaar received her A.B., magna cum laude, from Harvard College and earned an M.B.A. from the Wharton School of the University of Pennsylvania.

Ms. Wassenaar's experience in evaluating financial and strategic options and the operations of companies in our industry and as an investment banker make her a valuable member of our board.

Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of us. Our general partner and its affiliates will be reimbursed for all expenses incurred on our behalf, including the compensation of employees of USA Compression GP, LLC or its affiliates that perform services on our behalf. These expenses include all expenses necessary or appropriate to the conduct of our business and that are allocable to us. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. There is no cap on the amount that may be paid or reimbursed to our general partner or its affiliates for compensation or expenses incurred on our behalf.

Executive Compensation

Executive Summary

This Executive Compensation disclosure provides an overview of the executive compensation program for our named executive officers identified below. Our general partner intends to provide our named executive officers with compensation that is significantly performance based. For the year ended December 31, 2012, our named executive officers, or our NEOs, were:

- Eric D. Long, President and Chief Executive Officer;
- Joseph C. Tusa, Jr., Vice President, Chief Financial Officer and Treasurer; and
- David A. Smith, Vice President and President, Northeast Region.

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Summary Compensation Table

The following table sets forth certain information with respect to the compensation paid to our NEOs for the years ended December 31, 2011 and 2012.

Name and Principal Position	Year	Salary ($)	Unit Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)(2)	All Other Compensation ($)	Total ($)
Eric D. Long	2012	400,000		400,000	26,500(3)	826,500
President and Chief Executive Officer	2011	400,961		300,000	26,461(4)	727,422
Joseph C. Tusa, Jr.	2012	275,000		175,000	6,313(5)	456,313
Vice President, Chief Financial Officer and Treasurer	2011	275,000		150,000	6,346(6)	431,346
David A. Smith	2012	250,000		400,000	20,045(7)	670,045
Vice President and President, Northeast Region	2011	250,000		350,000	17,060(8)	617,060

(1) On December 23, 2010, each of our NEOs received awards of Class B Units in USA Compression Holdings. The Class B Units are intended to allow recipients to receive a percentage of profits generated by USA Compression Holdings over and above certain return hurdles, as described in more detail in the discussion under the heading " Discretionary Long Term Equity Incentive Awards" below. No awards were made to our NEOs in 2011 or 2012.

(2) Represents the awards earned under annual incentive bonus programs and commission programs, as applicable, for the years ended December 31, 2011 and 2012. For a discussion of the determination of the 2012 bonus amounts, see " Annual Performance-Based Compensation for 2012" below.

(3) Includes $18,000 of automobile allowance and $8,500 of employer contributions under the 401(k) plan.

(4) Includes $18,000 of automobile allowance and $8,461 of employer contributions under the 401(k) plan.

(5) Includes $6,313 of employer contributions under the 401(k) plan.

(6) Includes $6,346 of employer contributions under the 401(k) plan.

(7) Includes $9,960 of automobile allowance and $10,085 of employer contributions under the 401(k) plan.

(8) Includes $9,960 of automobile allowance and $7,100 of employer contributions under the 401(k) plan.

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Narrative Disclosure to Summary Compensation Table

Elements of the Compensation Program

Compensation for our NEOs consists primarily of the elements, and their corresponding objectives, identified in the following table.

Compensation Element	**Primary Objective**
Base salary	To recognize performance of job responsibilities and to attract and retain individuals with superior talent.
Annual performance-based compensation	To promote near-term performance objectives and reward individual contributions to the achievement of those objectives.
Discretionary long-term equity incentive awards	To emphasize long-term performance objectives, encourage the maximization of unitholder value and retain key executives by providing an opportunity to participate in the ownership of our partnership.
Severance benefits	To encourage the continued attention and dedication of key individuals and to focus the attention of key individuals when considering strategic alternatives.
Retirement savings (401(k)) plan	To provide an opportunity for tax-efficient savings.
Other elements of compensation and perquisites	To attract and retain talented executives in a cost-efficient manner by providing benefits with high perceived values at relatively low cost.

For 2012, the non-employee members of the USA Compression Holdings Board of Managers had primary authority to determine and approve compensation decisions with respect to our NEOs. Going forward, our NEOs will be employed and their compensation will be paid by our general partner or its subsidiary, subject to reimbursement by us. Following the consummation of this offering, the compensation of our NEOs will be determined by the board of directors of our general partner.

Base Compensation For 2012

Base salaries for our NEOs have generally been set at a level deemed necessary to attract and retain individuals with superior talent. Base salary increases are determined based upon the job responsibilities, demonstrated proficiency and performance of the executive officers and market conditions, each as assessed by the Board of Managers of USA Compression Holdings. No formulaic base salary increases are provided to the NEOs. Additionally, no changes to base salaries for our NEOs were made for the fiscal year ended December 31, 2012.

The current base salaries for our NEOs, including for our Chief Executive Officer, are set forth in the following table:

Name and Principal Position	**Current Base Salary ($)**
Eric D. Long President and Chief Executive Officer	400,000
Joseph C. Tusa, Jr. Vice President, Chief Financial Officer and Treasurer	275,000
David A. Smith Vice President and President, Northeast Region	250,000

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Annual Performance-Based Compensation For 2012

Each of our NEOs participates in a discretionary annual incentive bonus compensation program, under which incentive awards are determined annually, with reference to target bonus amounts that are set forth in their employment agreements. For 2012, the target bonus amounts for each of our NEOs were as follows: Mr. Long: $300,000; Mr. Tusa: $110,000; and Mr. Smith: $120,000. In making individual annual bonus decisions, the Board of Managers of USA Compression Holdings, following the recommendations of our Chief Executive Officer, does not rely on pre-determined performance goals or targets. Instead, determinations regarding annual bonus compensation awards are based on a subjective assessment of all reasonably available information, including the applicable executive's performance, business impact, contributions and leadership.

For 2012, our general partner's Board of Managers determined to provide each NEO with a 2012 annual bonus award above the NEO's target bonus, generally on what it viewed as strong leadership and overall financial performance. In addition, the Board of Managers sought to reward our NEOs for our operational results and significantly increased sales activity during the year. As a result of these considerations, Mr. Long received an annual incentive award equal to 133% of his target amount in recognition of his strong leadership in sales and operations, Mr. Smith received 167% of his target amount to recognize his strong sales performance and Mr. Tusa received an award equal to 159% of his target amount due to his leadership in building a strengthened financial and accounting team in 2012 and expanding and improving our credit facility.

Awards in 2012 were:

Eric D. Long	$	400,000
Joseph C. Tusa, Jr.	$	175,000
David A. Smith	$	200,000

Mr. Smith also receives commissions in an amount up to $200,000 annually based on a percentage of qualifying sales. Based on sales performance in 2012, as in prior recent years, Mr. Smith earned the maximum potential amount of commissions available under this arrangement.

Benefit Plans and Perquisites

We provide our executive officers, including our NEOs, with certain personal benefits and perquisites, which we do not consider to be a significant component of executive compensation but which we recognize are an important factor in attracting and retaining talented executives. Executive officers are eligible under the same plans as all other employees with respect to our medical, dental, vision, disability and life insurance plans and a defined contribution plan that is tax-qualified under Section 401(k) of the Internal Revenue Code and that we refer to as the 401(k) Plan. We also provide certain executive officers with an annual automobile allowance. We provide these supplemental benefits to our executive officers due to the relatively low cost of such benefits and the value they provide in assisting us in attracting and retaining talented executives. The value of personal benefits and perquisites we provide to each of our NEOs is set forth above in our " Summary Compensation Table."

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Discretionary Long-Term Equity Incentive Awards

Prior to the Holdings Acquisition, our NEOs historically received various forms of equity compensation, in the form of both capital and profits interests in us and our predecessor entities, and in connection with the Holdings Acquisition, each of our NEOs re-invested a substantial portion of the cash proceeds received in respect of his prior equity interests in certain classes of capital or profit interest units in USA Compression Holdings.

Our NEOs were also granted Class B Units of USA Compression Holdings at the time of the Holdings Acquisition. In connection with the Holdings Acquisition in December 2010, the Board of Managers also reserved additional Class B Units for future grants to NEOs and other key employees.

The Class B Units are profits interests that allow our NEOs to participate in the increase in value of USA Compression Holdings over and above an 8% annual and cumulative preferred return hurdle. The grants have time-based vesting requirements and are designed to not only compensate but also to motivate and retain the recipients by providing an opportunity for equity ownership by our NEOs. The grants to our NEOs also provide our NEOs with meaningful incentives to increase unitholder value over time.

Generally, the Class B Units have vesting schedules that are designed to encourage NEOs' continued employment or service with USA Compression Holdings or one of its affiliates, including us and our general partner. The Class B Units generally (i) vest twenty-five percent on the first anniversary of the date of grant (December 31, 2011 for grants made at the time of the Holdings Acquisition) and (ii) with respect to the remaining Class B Units, will vest in thirty-six monthly installments thereafter, subject to the NEO's continued employment on each applicable vesting date. See " Severance and Change in Control Arrangements" below for a description of the circumstances under which vesting of the Class B Units may be accelerated, including in connection with this offering.

In anticipation of our initial public offering, we intend to adopt a new long-term equity incentive plan, or the LTIP, and which is discussed in more detail under "2013 Long-Term Incentive Plan" below.

Outstanding Equity Awards at December 31, 2012

The following table provides information regarding the Class B Units in USA Compression Holdings held by the NEOs as of December 31, 2012. None of our NEOs held any option awards that were outstanding as of December 31, 2012.

	Unit Awards	
Name	**Number of Units That Have not Vested (#)**	**Market Value of Class B Units That Have Not Vested ($)(2)**
Eric D. Long	231,250(1)	
Joseph C. Tusa, Jr.	62,500(1)	
David A. Smith	62,500(1)	

(1) Represents the number of Class B Units in USA Compression Holdings that have not vested as of December 31, 2012. These Class B Units will vest in thirty-six equal monthly installments on each monthly anniversary of December 31, 2011.

(2) As described in footnote 1 to the " Summary Compensation Table" and in the discussion above under the heading " Discretionary Long Term Equity Incentive Awards," the Class B Units are intended to allow recipients to receive a percentage of profits generated by USA Compression Holdings over and above certain return hurdles. The Class B Units had no recognizable value as of December 31, 2012.

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Severance and Change in Control Arrangements

Our NEOs are entitled to severance payments and benefits upon certain terminations of employment and, in certain cases, in connection with a change in control of Holdings.

Each NEO currently has an employment agreement with USAC Operating which provides for severance benefits upon a termination of employment. In connection with the consummation of this offering, our general partner expects to enter into new employment agreements with each of our NEOs on terms that are substantially similar to these employment agreements. As described below, these agreements are substantially similar for each of the NEOs. In addition, pursuant to the Holdings Operating Agreement, our NEOs are entitled to accelerated vesting of certain Class B Units as described below.

Severance Arrangements

Each NEO's employment agreement, dated as of December 23, 2010, has an initial four-year term and is extended automatically for successive twelve-month periods thereafter unless either party delivers written notice to the other within ninety days prior to the expiration of the then-current employment term. Upon termination of an NEO's employment either by us for convenience or due to the NEO's resignation for good reason, subject to the timely execution of a general release of claims, the NEO is entitled to receive (i) an amount equal to one times his annual base salary, payable in equal semi-monthly installments over one year following termination (or, if such termination occurs within two years following a change in control, in a lump sum within thirty days following the termination of employment) and (ii) continued coverage for twenty-four months (or, with respect to Mr. Long, thirty months) under our group medical plan in which the executive and any of his dependents were participating immediately prior to his termination. Continued coverage under our group medical plan is subsidized for the first twelve months following termination, and Mr. Long is entitled to reimbursement by us to the extent the cost of such coverage exceeds $1,200 per month for the remainder of the applicable period. Additionally, upon a termination of an NEO's employment by us for convenience, by the NEO for good reason, or due to the NEO's death or disability, the NEO is entitled to receive a pro-rata portion of any earned annual bonus for the year in which termination occurs (calculated with reference to the performance targets established by the Board of Managers of USA Compression Holdings for that year). During employment and for two years following termination, each NEO's employment agreement prohibits him from competing with certain of our businesses.

As used in the NEOs' employment agreements, a termination for "convenience" means an involuntary termination for any reason, including a failure to renew the employment agreement at the end of an initial term or any renewal term, other than a termination for "cause." "Cause" is defined in the NEOs' employment agreements to mean (i) any material breach of the employment agreement or the Amended and Restated Limited Liability Company Agreement of USA Compression Holdings, or the Holdings Operating Agreement, by the executive, (ii) the executive's breach of any applicable duties of loyalty to us or any of our affiliates, gross negligence or misconduct, or a significant act or acts of personal dishonesty or deceit, taken by the executive, in the performance of the duties and services required of the executive that has a material adverse effect on us or any of our affiliates, (iii) conviction or indictment of the executive of, or a plea of nolo contendere by the executive to, a felony, (iv) the executive's willful and continued failure or refusal to perform substantially the executive's material obligations pursuant to the employment agreement or the Holdings Operating Agreement or follow any lawful and reasonable directive from the Board of Managers of USA Compression Holdings or, as applicable, the Chief Executive Officer, other than as a result of the executive's incapacity, or (v) a pattern of illegal conduct by the executive that is materially injurious to us or any of our affiliates or our or their reputation.

"Good reason" is defined in the NEOs' employment agreements to mean (i) a material breach by us of the employment agreement, the Holdings Operating Agreement, or any other material agreement with the executive, (ii) any failure by us to pay to the executive the amounts or benefits to which he is entitled, other than an isolated and inadvertent failure not committed in bad faith, (iii) a material reduction in the executive's duties, reporting relationships or responsibilities, (iv) a material reduction by us in the facilities or perquisites available to the executive or in the executive's base salary, other than a reduction that is generally applicable to all similarly situated employees, or (v) the relocation of the geographic location of the executive's principal place of employment by more than fifty miles from the location of the executive's principal place of employment as of December 23, 2010. With respect to Mr. Long's employment agreement, "good reason" also means the failure to appoint and maintain Mr. Long in the office of President and Chief Executive Officer.

Change in Control Benefits

Pursuant to the Holdings Operating Agreement, in the event of certain transactions, which could include a change in control, the vesting of certain Class B Units would be accelerated. The vesting of all unvested Class B Units would be accelerated either (i) upon a private liquidity event (generally defined as Riverstone's sale of 50.1% of its equity interests in USA Compression Holdings for cash, other than in connection with an initial public offering of securities) or (ii) upon a termination of an NEO's employment without cause or due to resignation by the executive for good reason, in each case, following a qualified public offering. In addition, upon a qualified public offering, 50% of each NEO's unvested Class B Units would vest.

The Class B Units generally allow our NEOs to participate in the increase in value, following the December 23, 2010 grant date of such units, of the equity of USA Compression Holdings in excess of a specified hurdle, as described in more detail above under " Discretionary Long-Term Equity Incentive Awards."

Upon the consummation of this offering, which constitutes a qualified public offering for purposes of certain vesting provisions of the NEO's Class B Units, 50% of each NEO's unvested Class B Units will vest and, if an NEO's employment is terminated by our general partner without cause or the NEO resigns for good reason following the consummation of this offering, the remaining unvested Class B Units will vest in full. As used in the Holdings Operating Agreement, "good reason" and "cause" have the meanings set forth in each NEO's employment agreement and described above in the section entitled " Severance Arrangements."

Director Compensation

For the year ended December 31, 2012, our NEOs who also served as directors did not receive additional compensation for their service as directors. Additionally, directors who were not officers, employees or paid consultants or advisors of us or our general partner did not receive compensation for their services as directors, except that Robert F. End received compensation for his service as a director during the quarter ended December 31, 2012, as set forth in the following table:

Name	Fees Earned or Paid in Cash ($)	Total
Robert F. End	18,750	18,750

Following the consummation of this offering, officers, employees or paid consultants or advisors of us or our general partner or its affiliates who also serve as directors will not receive additional compensation for their service as directors. Following the consummation of this offering, our directors who are not officers, employees or paid consultants or advisors of us or our general partner or its affiliates will receive cash and equity-based compensation for their services as directors. We expect that our director compensation program will initially consist of the following and will be subject to revision by the board of directors of our general partner from time to time:

- an annual cash retainer of $75,000,
- an additional annual retainer of $15,000 for service as the chair of any standing committee,
- meeting attendance fees of $2,000 per meeting attended, and

an annual equity-based award in the form of phantom units that will be granted under our LTIP, having a value as of the grant date of $75,000. Phantom unit awards are expected to be subject to vesting conditions and will be paid either on a current or deferred basis, in each case as will be determined at the time of grant of the awards.

Directors will also receive reimbursement for out-of-pocket expenses associated with attending such board or committee meetings and director and officer liability insurance coverage. Each director will be fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

2013 Long-Term Incentive Plan

Prior to the consummation of this offering, our general partner intends to adopt a 2013 Long-Term Incentive Plan, or LTIP, primarily for the benefit of our, our subsidiaries' and our general partner's eligible officers, employees and directors. The description of the LTIP set forth below is a summary of the anticipated material features of the LTIP. This summary, however, does not purport to be a complete description of all of the anticipated provisions of the LTIP.

The LTIP will provide for the grant, from time to time at the discretion of the board of directors of our general partner, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards. Subject to adjustment in the event of certain transactions or changes in capitalization, an aggregate of 1,410,000 common units may be delivered pursuant to awards under the LTIP. Units that are cancelled or forfeited will be available for delivery pursuant to other awards. Units that are withheld to satisfy our general partner's tax withholding obligations or payment of an award's exercise price will not be available for future awards. We expect that the LTIP will be administered by our general partner's board of directors, though such administration function may be delegated to a committee that may be appointed by the board to administer the LTIP. The LTIP will be designed to promote our interests, as well as the interests of our unitholders, by rewarding the officers, employees and directors of us, our subsidiaries and our general partner for delivering desired performance results, as well as by strengthening our and our general partner's ability to attract, retain and motivate qualified individuals to serve as directors, consultants and employees.

Unit Awards

The administrator of the LTIP may grant unit awards to eligible individuals under the LTIP. A unit award is an award of common units that are fully vested upon grant and are not subject to forfeiture. Unit awards may be paid in addition to, or in lieu of, cash that would otherwise be payable to a participant with respect to a bonus or an incentive compensation award. The unit award may be wholly discretionary in amount or it may be paid with respect to a bonus or an incentive compensation award the amount of which is determined based on the achievement of performance criteria or other factors.

Restricted Units and Phantom Units

A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. The administrator of the LTIP may make grants of restricted and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the administrator may determine are appropriate, including the period over which restricted or phantom units will vest. The administrator of the LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change of control (as defined in the LTIP) or as otherwise described in an award agreement.

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Distributions made by us with respect to awards of restricted units may be subject to the same vesting requirements as the restricted units. The administrator of the LTIP, in its discretion, may also grant tandem distribution equivalent rights with respect to phantom units. Distribution equivalent rights are rights to receive an amount equal to all or a portion of the cash distributions made on units during the period a phantom unit remains outstanding.

Unit Options and Unit Appreciation Rights

The LTIP may also permit the grant of options and unit appreciation rights covering common units. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the administrator of the LTIP may determine, consistent with the LTIP; however, a unit option or unit appreciation right must have an exercise price equal to at least the fair market value of a common unit on the date of grant.

Other Unit-Based Awards

The LTIP may also permit the grant of "other unit-based awards," which are awards that, in whole or in part, are valued or based on or related to the value of a unit. The vesting of an other unit-based award may be based on a participant's continued service, the achievement of performance criteria or other measures. On vesting or on a deferred basis upon specified future dates or events, an other unit-based award may be paid in cash and/or in units (including restricted units), as the administrator of the LTIP may determine.

Source of Common Units; Cost

Common units to be delivered with respect to awards may be newly-issued units, common units acquired by us or our general partner in the open market, common units already owned by our general partner or us, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. With respect to awards made to employees of our general partner, our general partner will be entitled to reimbursement by us for the cost incurred in acquiring such common units or, with respect to unit options, for the difference between the cost it incurs in acquiring these common units and the proceeds it receives from an optionee at the time of exercise of an option. Thus, we will bear the cost of all awards under the LTIP. If we issue new common units with respect to these awards, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash by our general partner, our general partner will be entitled to reimbursement by us for the amount of the cash settlement.

Amendment or Termination of Long-Term Incentive Plan

The administrator of the LTIP, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the tenth anniversary of the date it was initially adopted by our general partner. The administrator of the LTIP will also have the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would materially impair the vested rights of the participant without the consent of the affected participant or result in taxation to the participant under Section 409A of the Code.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units that will be issued upon the consummation of this offering and the related transactions, assuming the underwriters do not exercise their option to purchase additional common units, and held by:

- each person who then will beneficially own 5% or more of the then outstanding units;
- all of the directors of USA Compression GP, LLC;
- each executive officer of USA Compression GP, LLC; and
- all directors and officers of USA Compression GP, LLC as a group.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them and their address is 100 Congress Avenue, Suite 450, Austin, Texas 78701.

Name of Beneficial Owner	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned	Subordinated Units to be Beneficially Owned	Percentage of Subordinated Units to be Beneficially Owned	Percentage of Common and Subordinated Units to be Beneficially Owned
USA Compression Holdings(1)	4,048,588	26.9%	14,048,588	100.0%	62.2%
Eric D. Long	12,500(2)	*			
Joseph C. Tusa, Jr.					
J. Gregory Holloway					
David A. Smith					
Dennis J. Moody					
Kevin M. Bourbonnais					
William H. Shea, Jr.					
Olivia C. Wassenaar					
Andrew W. Ward					
Robert F. End					
Jim H. Derryberry					
All directors and officers as a group (11 persons)					

* Less than 1%.

(1) Eric D. Long, Joseph C. Tusa, Jr., Kevin M. Bourbonnais, J. Gregory Holloway, David A. Smith and Dennis J. Moody, each of whom are executive officers of our general partner, Aladdin Partners, L.P., a limited partnership affiliated with Mr. Long, and R/C IV USACP Holdings, L.P., or R/C Holdings, own equity interests in USA Compression Holdings. USA Compression Holdings is managed by a three-person board of managers consisting of Mr. Long, Mr. Ward and Ms. Wassenaar. The board of managers exercises investment discretion and control over the units held by USA Compression Holdings.

R/C Holdings is the record holder of approximately 97.6% of the limited liability company interests of USA Compression Holdings and is entitled to elect a majority of the members of the board of managers of USA Compression Holdings. R/C Holdings is an investment partnership affiliated with Riverstone/Carlyle Global Energy and Power Fund IV, L.P., or R/C IV. Management and control of R/C Holdings is with its general partner, which is in turn managed and controlled by its general partner, R/C Energy GP IV, LLC, an affiliate of R/C IV. R/C Energy GP IV, LLC is managed by an eight-person management committee that includes Andrew W. Ward. The principal business address of R/C Energy GP IV, LLC is 712 Fifth Avenue, 51st Floor, New York, New York 10019.

Mr. Long, Mr. Ward and Ms. Wassenaar, each of whom are members of the board of directors of our general partner, each disclaim beneficial ownership of the units owned by USA Compression Holdings.

(2) Includes 10,000 common units held by certain trusts of which Mr. Long is the trustee and 1,500 common units held by Mr. Long's spouse.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, our general partner and its affiliates will own 4,048,588 common units and 14,048,588 subordinated units representing an aggregate 61.0% limited partner interest in us (or 4,015,588 common and 14,048,588 subordinated units, representing an aggregate 57.6% limited partner interest in us, if the underwriters exercise their option to purchase additional common units in full). In addition, our general partner will own a 2.0% general partner interest in us and all of our incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the ongoing operation and any liquidation of USA Compression Partners, LP. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Pre-IPO Stage

The consideration received by our general partner and its affiliates prior to or in connection with this offering	4,048,588 common units; 14,048,588 subordinated units; all of our incentive distribution rights; and 2.0% general partner interest.

Operational Stage