CVR ENERGY INC
Form S-1
June 19, 2008

Table of Contents

As filed with the Securities and Exchange Commission on June 19, 2008

Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933
CVR ENERGY, INC.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**2911**	**61-1512186**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

2277 Plaza Drive, Suite 500
Sugar Land, Texas 77479
(281) 207-3200
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)

John J. Lipinski
2277 Plaza Drive, Suite 500
Sugar Land, Texas 77479
(281) 207-3200
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

With a copy to:

Stuart H. Gelfond **Michael A. Levitt** **Fried, Frank, Harris, Shriver & Jacobson LLP** **One New York Plaza** **New York, New York 10004** **(212) 859-8000**	**Peter J. Loughran** **Debevoise & Plimpton LLP** **919 Third Avenue** **New York, New York 10022** **(212) 909-6000**

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

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

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

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

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

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered(1)	Proposed Maximum Offering Price per Share(2)	Proposed Maximum Aggregate Offering Price(1)(2)	Amount of Registration Fee
Common Stock, $0.01 par value	11,500,000	$25.51	$293,365,000	$11,530

(1) Includes the number of shares, or the offering price of shares, as the case may be, which the underwriters have the option to purchase.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(c) of the Securities Act of 1933, as amended, based on the average of the high and low prices of the Registrant s Common Stock as reported on the New York Stock Exchange on June 13, 2008. The actual amount received by the selling shareholders will be based upon fluctuating market prices.

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

Table of Contents

Subject to Completion. Dated June 19, 2008.

10,000,000 Shares

CVR Energy, Inc.

Common Stock

All of the shares of common stock to be sold in this offering are being sold by the selling stockholders identified in this prospectus. CVR Energy, Inc. will not receive any of the proceeds from the sale of shares by the selling stockholders.

Our common stock is listed on the New York Stock Exchange under the symbol CVI. The last reported sale price of our common stock on June 18, 2008 was $24.98 per share.

Concurrently with this offering, CVR Energy, Inc. is offering $125,000,000 aggregate principal amount of its % Convertible Senior Notes due 2013 in a registered public offering. The consummation of this offering is not conditioned upon the concurrent consummation of the offering of the convertible notes and vice versa.

See Risk Factors beginning on page 24 to read about factors you should consider before buying shares of the common stock.

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

	Per Share	Total
Public offering price	$	$

Underwriting discount	$	$
Proceeds, before expenses, to the selling stockholders	$	$

To the extent that the underwriters sell more than 10,000,000 shares of common stock, the underwriters have the option to purchase up to an additional 1,500,000 shares of common stock from certain of the selling stockholders at the public offering price less the underwriting discount. CVR Energy will not receive any of the proceeds from the sale of shares by certain of the selling stockholders pursuant to any exercise of the underwriters option to purchase additional shares.

The underwriters expect to deliver the shares against payment in New York, New York on , 2008.

Goldman, Sachs & Co. **Deutsche Bank Securities**

Citi **Credit Suisse**

Prospectus dated , 2008.

Table of Contents

Table of Contents

PROSPECTUS SUMMARY

This summary highlights selected information contained elsewhere in this prospectus. You should carefully read the entire prospectus, including the Risk Factors and the consolidated financial statements and related notes included elsewhere in this prospectus, before making an investment decision. In this prospectus, all references to the Company, CVR Energy, we, us, and our refer to CVR Energy, Inc. and its consolidated subsidiaries, unless the context otherw requires or where otherwise indicated. References in this prospectus to the nitrogen fertilizer business and the Partnership refer to CVR Partners, LP, the entity that owns and operates the nitrogen fertilizer facility. We currently own all of the interests in CVR Partners, LP (other than the managing general partner interest and associated incentive distribution rights, which are held by CVR GP, LLC, or Fertilizer GP, an entity owned by our controlling stockholders and certain members of our senior management team). See The Nitrogen Fertilizer Limited Partnership. You should also see the Glossary of Selected Terms beginning on page 282 for definitions of some of the terms we use to describe our business and industry. We use non-GAAP measures in this prospectus, including Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. For a reconciliation of this measure to net income, see footnote 4 under Summary Consolidated Financial Information.

CVR Energy, Inc.

We are an independent refiner and marketer of high value transportation fuels and, through a limited partnership, a producer of ammonia and urea ammonia nitrate, or UAN, fertilizers. We are one of only seven petroleum refiners and marketers located within the mid-continent region (Kansas, Oklahoma, Missouri, Nebraska and Iowa). The nitrogen fertilizer business is the only operation in North America that utilizes a coke gasification process, and at current natural gas and petroleum coke, or pet coke, prices, the lowest cost producer and marketer of ammonia and UAN fertilizers in North America.

Our petroleum business includes a 115,000 barrel per day, or bpd, complex full coking medium-sour crude refinery in Coffeyville, Kansas. In addition, our supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma and southwestern Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of approximately 1.2 million barrels and (4) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and to customers at throughput terminals on Magellan Midstream Partners L.P. s refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Partners L.P. and NuStar Energy L.P. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States, served by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude oil variety in the world capable of being transported by pipeline.

The nitrogen fertilizer business consists of a nitrogen fertilizer manufacturing facility comprised of (1) a 1,225 ton-per-day ammonia unit, (2) a 2,025 ton-per-day UAN unit and (3) an 84 million standard cubic foot per day gasifier complex. The nitrogen fertilizer business is the only operation in North America that utilizes a coke gasification process to produce ammonia (based on data provided by Blue Johnson & Associates). In 2007, approximately 72% of the ammonia produced by the fertilizer plant was further upgraded to UAN fertilizer (a solution of urea, ammonium nitrate and water used as a fertilizer). By using pet coke (a coal-like substance that is produced during the refining process) instead of natural gas as a primary raw material, at current natural gas and pet coke prices the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN fertilizers in

Table of Contents

North America. Furthermore, on average during the last four years, over 75% of the pet coke utilized by the fertilizer plant was produced and supplied to the fertilizer plant as a by-product of our refinery. As such, the nitrogen fertilizer business benefits from high natural gas prices, as fertilizer prices generally increase with natural gas prices, without a directly related change in cost (because pet coke rather than natural gas is used as a primary raw material). During the second quarter of 2008, we are enjoying unprecedented fertilizer prices which have contributed favorably to our earnings.

We generated combined net sales of $2.4 billion, $3.0 billion and $3.0 billion and operating income of $270.8 million, $281.6 million and $186.6 million for the fiscal years ended December 31, 2005, 2006 and 2007, respectively. Our petroleum business generated $2.3 billion, $2.9 billion and $2.8 billion of our combined net sales, respectively, over these periods, with the nitrogen fertilizer business generating substantially all of the remainder. In addition, during these periods, our petroleum business contributed $199.7 million, $245.6 million and $144.9 million, respectively, of our combined operating income with substantially all of the remainder contributed by the nitrogen fertilizer business. For the three months ended March 31, 2008, we generated combined net sales of $1.22 billion and operating income of $87.4 million. Our petroleum business generated $1.17 billion of our combined net sales and $63.6 million of our combined operating income during this period, with substantially all of the remainder contributed by the nitrogen fertilizer business.

Key Market Trends

We have identified several key factors which we believe are influencing the outlook for the refining and nitrogen fertilizer industries.

For the refining industry, these factors include the following:

- High capital costs, historical excess capacity and environmental regulatory requirements that have limited the construction of new refineries in the United States over the past 30 years.
- Refining capacity shortage in the mid-continent region, as certain regional markets in the U.S. are subject to insufficient local refining capacity to meet regional demands. This should result in local refiners earning higher margins on product sales than those who must rely on pipelines and other modes of transportation for supply.
- Crack spreads are increasing in terms of absolute value with dramatically higher crude oil costs, but are substantially narrower as a percentage of crude oil costs, which has reduced oil refinery profitability.
- A shift in market fundamentals for global petroleum refiners. The most profitable end products for refiners have shifted from gasoline products to distillate products.
- Increasing demand for sweet crude oils and higher incremental production of lower-cost sour crude that are expected to provide a cost advantage to sour crude processing refiners.
- U.S. fuel specifications, including reduced sulfur content, reduced vapor pressure and the addition of oxygenates such as ethanol, that should benefit refiners who are able to efficiently produce fuels that meet these specifications.
- Limited competitive threat from foreign refiners due to sophisticated U.S. fuel specifications and increasing foreign demand for refined products.

For the nitrogen fertilizer industry, these factors include the following:

- Nitrogen fertilizer prices in the United States are experiencing all-time highs. Based on industry projections, including from Blue Johnson, these high prices are forecast to continue for the next several years.

- Nitrogen fertilizer prices have been decoupled from their historical correlation with natural gas prices in recent years, and increased substantially more than natural gas prices in 2007 and

2008 (based on data provided by Blue Johnson). Moreover, natural gas prices are currently higher in the United States and Canada compared to prevailing prices in the years prior to 2004. High North American natural gas prices contribute to the currently high prices for nitrogen-based fertilizers in the United States.

The Energy Independence and Security Act of 2007 requires fuel producers to use at least 36 billion gallons of biofuel (such as ethanol) by 2022, a nearly five-fold increase over current levels. The increase in grain production necessary to meet this requirement is expected to result in rising demand for nitrogen-based fertilizers.

World population and economic growth, combined with changing dietary trends in many nations, has significantly increased demand for U.S. agricultural production and exports. Increasing U.S. crop production requires higher application rates of fertilizers, primarily nitrogen-based fertilizers.

Both of our industries are cyclical and volatile and have experienced downturns in the past. See Risk Factors.

Our Competitive Strengths

Regional Advantage and Strategic Asset Location. Our refinery is located in the southern portion of the PADD II Group 3 distribution area. Because refined product demand in this area exceeds production, the region has historically required U.S. Gulf Coast imports to meet demand. We estimate that this favorable supply/demand imbalance combined with our lower pipeline transportation cost as compared to the U.S. Gulf Coast refiners has allowed us to generate refining margins, as measured by the 2-1-1 crack spread, that have exceeded U.S. Gulf Coast refining margins by approximately $2.14 per barrel on average for the last four years. The 2-1-1 crack spread is a general industry standard that approximates the per barrel refining margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of heating oil.

In addition, the nitrogen fertilizer business is geographically advantaged to supply nitrogen fertilizer products to markets in Kansas, Missouri, Nebraska, Iowa, Illinois and Texas without incurring intermediate transfer, storage, barge or pipeline freight charges. Because the nitrogen fertilizer business does not incur these costs, this geographic advantage provides it with a distribution cost advantage over competitors not located in the farm belt who transport ammonia and UAN from the U.S. Gulf Coast, based on recent freight rates and pipeline tariffs for U.S. Gulf Coast importers.

Access to and Ability to Process Multiple Crude Oils. Since June 2005 we have significantly expanded the variety of crude grades processed in any given month. While our proximity to the Cushing crude oil trading hub minimizes the likelihood of an interruption to our supply, we intend to further diversify our sources of crude oil. Among other initiatives in this regard, we maintain capacity on the Spearhead pipeline, which connects Chicago to the Cushing hub. We have also committed to additional pipeline capacity on the proposed Keystone pipeline project currently under development by TransCanada Keystone Pipeline, LP which will provide us with access to incremental oil supplies from Canada. We also own and operate a crude gathering system serving northern Oklahoma, central Kansas and southwestern Nebraska, which allows us to acquire quality crudes at a discount to West Texas intermediate crude oil, or WTI, which is used as a benchmark for other crude oils.

High Quality, Modern Refinery with Solid Track Record. Our refinery s complexity allows us to optimize the yields (the percentage of refined product that is produced from crude and other feedstocks) of higher value transportation fuels (gasoline and distillate), which currently account for approximately 94% of our liquid production output. Complexity is a measure of a refinery s ability to process lower quality crude in an economic manner; greater complexity makes a refinery more profitable. From 1995 through March 31, 2008, we have invested approximately $725 million to modernize our oil refinery and to meet more stringent U.S. environmental, health and safety

requirements. As a result, our refinery s complexity has increased from 10.0 to 12.1, and we have achieved significant increases in our refinery crude oil throughput rate, from an average of less than 90,000 bpd prior to June 2005 to an average of over 102,000 bpd in the second quarter of 2006, over 94,500 bpd for all of 2006 and over 110,000 bpd in the fourth quarter of 2007 with maximum daily rates in excess of 120,000 bpd for the fourth quarter of 2007.

Unique Coke Gasification Fertilizer Plant. The nitrogen fertilizer plant, completed in 2000, is the newest fertilizer facility in North America and the only one of its kind in North America using a pet coke gasification process to produce ammonia. While this facility is unique to North America, gasification technology has been in use for over 50 years in various industries to produce fuel, chemicals and other products from carbon-based source materials. Because it uses significantly less natural gas in the manufacture of ammonia than other domestic nitrogen fertilizer plants, with the currently high price of natural gas the nitrogen fertilizer business feedstock cost per ton for ammonia is considerably lower than that of its natural gas-based fertilizer plant competitors. We estimate that the facility s production cost advantage over U.S. Gulf Coast ammonia producers is sustainable at natural gas prices as low as $2.50 per MMBtu (at June 16, 2008, the price of natural gas was $12.93 per MMBtu).

Experienced Management Team. In conjunction with the acquisition of our business in June 2005 by funds affiliated with Goldman, Sachs & Co. and Kelso & Company, L.P., or the Goldman Sachs Funds and the Kelso Funds, a new senior management team was formed that combined selected members of existing management with experienced new members. Our senior management team averages over 28 years of refining and fertilizer industry experience and, in coordination with our broader management team, has increased our operating income and stockholder value since June 2005.

Mr. John J. Lipinski, our Chief Executive Officer, has over 36 years of experience in the refining and chemicals industries, and prior to joining us in connection with the acquisition of Coffeyville Resources in June 2005, was in charge of a 550,000 bpd refining system and a multi-plant fertilizer system. Mr. Stanley A. Riemann, our Chief Operating Officer, has over 34 years of experience, and prior to joining us in March 2004, was in charge of one of the largest fertilizer manufacturing systems in the United States. Mr. James T. Rens, our Chief Financial Officer, has over 19 years of experience in the energy and fertilizer industries, and prior to joining us in March 2004, was the chief financial officer of two fertilizer manufacturing companies.

Our Business Strategy

The primary business objectives for our refinery business are to increase value for our stockholders and to maintain our position as an independent refiner and marketer of refined fuels in our markets by maximizing the throughput and efficiency of our petroleum refining assets. In addition, management s business objectives on behalf of the nitrogen fertilizer business are to increase value for our stockholders and maximize the production and efficiency of the nitrogen fertilizer facilities. We intend to accomplish these objectives through the following strategies:

Pursuing Organic Expansion Opportunities. We continually evaluate opportunities to expand our existing asset base and consider capital projects that accentuate our core competitiveness in petroleum refining. We are also evaluating projects that will improve our ability to process heavy crude oil feedstocks and to increase our overall operating flexibility with respect to crude oil slates. In addition, management also continually evaluates capital projects that are intended to enhance the Partnership s competitiveness in nitrogen fertilizer manufacturing.

Increasing the Profitability of Our Existing Assets. We strive to improve our operating efficiency and to reduce our costs by controlling our cost structure. We intend to make investments to improve the efficiency of our operations and pursue cost saving initiatives. We have recently completed the greenfield construction of a new continuous catalytic reformer. This project is expected to increase the profitability of our petroleum business through increased refined product yields and the

Table of Contents

elimination of scheduled downtime associated with the reformer that was replaced. In addition, this project reduces the dependence of our refinery on hydrogen supplied by the fertilizer facility, thereby allowing the nitrogen fertilizer business to generate higher margins by using the hydrogen to produce ammonia and UAN. The nitrogen fertilizer business expects, over time, to convert 100% of its production to higher-margin UAN.

Seeking Strategic Acquisitions. We intend to consider strategic acquisitions within the energy industry that are beneficial to our shareholders. We will seek acquisition opportunities in our existing areas of operation that have the potential for operational efficiencies. We may also examine opportunities in the energy industry outside of our existing areas of operation and in new geographic regions. In addition, working on behalf of the Partnership, management may pursue strategic and accretive acquisitions within the fertilizer industry, including opportunities in different geographic regions. We have no agreements or understandings with respect to any acquisitions at the present time.

Pursuing Opportunities to Maximize the Value of the Nitrogen Fertilizer Business. Our management, acting on behalf of the Partnership, will continually evaluate opportunities that are intended to enable the Partnership to grow its distributable cash flow. Management s strategies specifically related to the growth opportunities of the Partnership include the following:

> ***Expanding UAN Production.*** The nitrogen fertilizer business is moving forward with an approximately \$120 million nitrogen fertilizer plant expansion, of which approximately \$11 million was incurred as of March 31, 2008. This expansion is expected to permit the nitrogen fertilizer business to increase its UAN production and to result in its UAN manufacturing facility consuming substantially all of its net ammonia production. This should increase the nitrogen fertilizer plant s margins because UAN has historically been a higher margin product than ammonia. The UAN expansion is expected to be complete in July 2010 and it is estimated that it will result in an approximately 50% increase in the nitrogen fertilizer business annual UAN production. The company has also begun to acquire or lease offsite UAN storage facilities and continues to expand this program.
>
> ***Executing Several Efficiency-Based and Other Projects.*** The nitrogen fertilizer business is currently engaged in several efficiency-based and other projects in order to reduce overall operating costs, incrementally increase its ammonia production and utilize byproducts to generate revenue. For example, by redesigning the system that segregates carbon dioxide, or CO_2, during the gasification process, the nitrogen fertilizer business estimates that it will be able to produce approximately 25 tons per day of incremental ammonia, worth approximately \$6 million per year at current market prices. The nitrogen fertilizer business estimates that this project will cost approximately \$7 million (of which none has yet been incurred) and will be completed in 2010. The nitrogen fertilizer business has a proven track record of operating gasifiers and is well positioned to offer operating and technical services as a third-party operator to other gasifier-based projects.
>
> ***Evaluating Construction of a Third Gasifier Unit and a New Ammonia Unit and UAN Unit at the Nitrogen Fertilizer Plant***. The nitrogen fertilizer business has engaged a major engineering firm to help it evaluate the construction and operation of an additional gasifier unit to produce a synthesis gas from pet coke. It is expected that the addition of a third gasifier unit, together with additional ammonia and UAN units, to the nitrogen fertilizer business operations could result, on a long-term basis, in an increase in UAN production of approximately 75,000 tons per month. This project is in its earliest stages of review and is still subject to numerous levels of internal analysis.

Other opportunities our management may consider on behalf of the Partnership in the event that its managing general partner proceeds with an initial offering include acquiring certain of our petroleum business ancillary assets and providing incremental pipeline transportation and storage infrastructure services to our petroleum business. There are currently no agreements or understandings in place with respect to any such acquisitions or opportunities, and there can be no assurance that the Partnership would be able to operate any of these assets or businesses profitably.

Nitrogen Fertilizer Limited Partnership

In conjunction with the closing of our initial public offering in October 2007, the nitrogen fertilizer business was transferred to CVR Partners, LP, or the Partnership. The Partnership has two general partners: a managing general partner, which is owned by the Goldman Sachs Funds, the Kelso Funds and our senior management, and a second general partner, owned by us.

We own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs described below) and are currently entitled to all cash distributed by the Partnership. The managing general partner is not entitled to participate in Partnership distributions except in respect of its incentive distribution rights, or IDRs, which entitle it to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above $0.4313 per unit. The Partnership will not make any distributions with respect to the IDRs until the aggregate adjusted operating surplus (as defined on page 234) generated by the Partnership during the period from October 24, 2007 through December 31, 2009 has been distributed in respect of the interests which we hold and/or the Partnership s common and subordinated units (none of which are yet outstanding but which would be issued if the Partnership consummates an equity offering in the future). In addition, there will be no distributions paid on the managing general partner s IDRs for so long as the Partnership or its subsidiaries are guarantors under our credit facilities.

While we are initially entitled to receive all cash that is distributed by the Partnership, the partnership agreement provides that, once the Partnership has distributed all aggregate adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009, the managing general partner will be entitled to receive distributions on its IDRs only after we have received a quarterly distribution of $0.4313 per unit (or $52 million per year in the aggregate, assuming we continue to own all of the Partnership s interests that we currently own) from the Partnership. This quarterly distribution amount does not represent an amount that the Partnership currently intends to distribute to us, but represents the contractual term establishing our and the managing general partner s relative right to quarterly distributions from the Partnership, subject to the other limitations set forth in the partnership agreement and described herein. This amount may be changed at the time of the Partnership s initial offering, if any. The percentage of available cash distributed by the Partnership we receive will be limited (1) if the Partnership issues common units in a public or private offering, in which event all or a portion of our interests in the Partnership will become subordinated units and the balance, if any, will become common units, (2) if we sell or are required to sell any of our special units, and (3) at such time as the managing general partner begins to receive distributions with respect to its IDRs.

The Partnership is operated by our senior management pursuant to a services agreement among us, the managing general partner and the Partnership. We pay all of our senior management s compensation, and the Partnership reimburses us for the time our senior management spends working for the Partnership. The Partnership is managed by the managing general partner and us, as special general partner. As special general partner of the Partnership, we have (1) joint management rights regarding the appointment, termination and compensation of the chief executive officer and chief financial officer of the managing general partner, (2) the right to designate two members of the board of directors of the managing general partner and (3) joint management rights regarding specified major business decisions relating to the Partnership.

The Partnership filed a registration statement in February 2008 for an initial public offering of its common units. On June 13, 2008, we announced that the managing general partner of the Partnership has decided to postpone indefinitely the Partnership s initial public offering due to current market conditions for master limited partnerships.

The Partnership subsequently requested the registration statement be withdrawn. We believe maintaining the fertilizer business within the

Table of Contents

Company provides greater value for CVR Energy shareholders than would be the case if the Partnership became a publicly-traded partnership at this time. The Partnership may elect to move forward with a public or private offering in the future. Any future public or private offering by the Partnership would be made solely at the discretion of the Partnership s managing general partner, subject to our specified joint management rights, and would be subject to market conditions and negotiation of terms acceptable to the Partnership s managing general partner. In connection with the Partnership s initial public or private offering, if any, the Partnership may require us to include a sale of a portion of our interests in the Partnership. If the Partnership becomes a public company, we may consider a secondary offering of interests which we own. We cannot assure you that any such transaction will be consummated.

For more detailed information about the Partnership, see The Nitrogen Fertilizer Limited Partnership.

Cash Flow Swap

In conjunction with the acquisition of our business by Coffeyville Acquisition LLC, on June 16, 2005, Coffeyville Acquisition LLC entered into a series of commodity derivative arrangements, or the Cash Flow Swap, with J. Aron & Company, or J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The derivative took the form of three New York Mercantile Exchange, or NYMEX, swap agreements whereby if crack spreads in absolute terms fall below the fixed level, J. Aron agreed to pay the difference to us, and if crack spreads in absolute terms rise above the fixed level, we agreed to pay the difference to J. Aron. The Cash Flow Swap was assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005.

Based on crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010, so long as at the time of reduction or termination, we pay the amount of unrealized losses associated with the amount reduced or terminated.

We entered into the Cash Flow Swap for the following reasons:

- Debt was used as part of the acquisition financing in June 2005 which required the introduction of a financial risk management tool intended to mitigate a portion of the inherent commodity price based volatility in our cash flow and preserve our ability to service debt; and

- Given the size of the capital expenditure program contemplated by us at the time of the June 2005 acquisition, we considered it necessary to enter into a derivative arrangement to reduce the volatility of our cash flow and to ensure an appropriate return on the incremental invested capital.

The current environment of high and rising crude oil prices has led to higher crack spreads in absolute terms but significantly narrower crack spreads as a percentage of crude oil prices. As a result, the Cash Flow Swap, under which payments are calculated based on crack spreads in absolute terms, has had and continues to have a material negative impact on our earnings. Due to the Cash Flow Swap, we estimate we will owe J. Aron approximately $54 million on July 8, 2008 for crude oil we settled or will settle with respect to the quarter ending June 30, 2008, based on June 16, 2008 pricing. We also owe J. Aron $123.7 million plus accrued interest ($5.8 million as of June 1, 2008) on August 31, 2008 under deferral arrangements we entered into because of the temporary cessation of our operations on June 30, 2007 due to the flood. For more information on the Cash Flow Swap, please see Certain Relationships and Related Party Transactions Transactions with the Goldman Sachs Funds and the Kelso Funds J. Aron & Company and Management s Discussion and

Analysis of Financial Condition and Results of Operations Factors Affecting Comparability of Our Financial Results J. Aron Deferrals.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current United States generally accepted accounting principles, or GAAP. As a result, our periodic statements of operations reflect material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements. Given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap as a key indicator of our business performance and believes that this non-GAAP measure is a useful measure for investors in analyzing our business. For a discussion of the calculation and use of this measure, see footnote 4 to our Summary Consolidated Financial Information.

Convertible Notes Offering

Concurrently with this offering of common stock by our selling stockholders, we are offering $125.0 million aggregate principal amount of % Convertible Senior Notes due 2013, or the convertible notes offering, in a registered public offering. We intend to use the net proceeds from the convertible notes offering for general corporate purposes, which may include using a portion of the proceeds to pay amounts owed to J. Aron under the Cash Flow Swap and for future capital investments. We cannot give any assurance that the convertible senior notes offering will be completed on the terms set forth in the convertible senior notes offering registration statement or at all. The consummation of this offering is not conditioned upon the consummation of the offering of the convertible senior notes and vice versa.

Recent Developments

During the second quarter of 2008, we are enjoying unprecedented fertilizer prices which have contributed favorably to our earnings. Strong industry fundamentals have led current demand for nitrogen fertilizers to all time highs. U.S. corn inventories at the end of the 2008-2009 fertilizer year are projected to be at 673 million bushels, which is the lowest level since 1995-1996. Corn prices are at record high levels, and corn planting for 2008-2009 is projected to be higher than 2007-2008. Nitrogen fertilizer prices are at record high levels due to increased demand and increasing worldwide natural gas prices. In addition, nitrogen fertilizer prices, which historically showed a positive correlation with natural gas prices, have been decoupled from, and increased substantially more than, natural gas prices in 2007 and 2008. In addition to demand driven by biofuel fuel production, the quest for healthier lives and better diets in developing countries is a primary driving factor behind the increased global demand for fertilizers. As of June 16, 2008, our order book for UAN included 367,825 tons at an average netback price of $326.56 per ton and 34,898 tons of ammonia at an average netback price of $620.61 per ton.

At the same time, however, crude oil prices have reached record levels, and while crack spreads have increased to historically high absolute values, they are below historical levels as a percentage of crude oil prices. Because crack spreads as a percentage of crude oil prices have not kept pace with increasing crude oil prices, our earnings will be negatively impacted in the second quarter of 2008. The Cash Flow Swap will also have a material negative impact on our earnings through at least June 2009 due to the fact that losses on the Cash Flow Swap increase as crack spreads in absolute terms increase. In addition, our second quarter has been negatively impacted by unplanned downtime at the fertilizer plant and the refinery and increase in non-cash share-based compensation costs as a result of our increased stock price.

We have begun negotiations to enter into a new $25.0 million senior secured term loan, or the proposed senior secured credit facility, which we anticipate will contain covenants substantially similar to our existing credit facility. We have not entered into any agreement regarding this new credit facility,

and there is no guarantee that we will be able to enter into the proposed senior secured credit facility on the terms described herein or at all.

Our History

Prior to March 3, 2004, our refinery assets and the nitrogen fertilizer plant were operated as a small component of Farmland Industries, Inc., or Farmland, an agricultural cooperative. Farmland filed for bankruptcy protection on May 31, 2002. Coffeyville Resources, LLC, a subsidiary of Coffeyville Group Holdings, LLC, won the bankruptcy court auction for Farmland s petroleum business and a nitrogen fertilizer plant and completed the purchase of these assets on March 3, 2004. On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, all of the subsidiaries of Coffeyville Group Holdings, LLC were acquired by Coffeyville Acquisition LLC, an entity principally owned by the Goldman Sachs Funds and the Kelso Funds.

On October 26, 2007, CVR Energy completed its initial public offering. CVR Energy was formed as a wholly-owned subsidiary of Coffeyville Acquisition LLC in September 2006 in order to complete the initial public offering of the businesses acquired by Coffeyville Acquisition LLC. In October 2007, the nitrogen fertilizer business was transferred to the Partnership and the Partnership s managing general partner was sold to a new entity owned by the Goldman Sachs Funds, the Kelso Funds and certain members of our senior management team.

Prior to our initial public offering, Coffeyville Acquisition LLC directly or indirectly owned all of our subsidiaries. We were formed as a wholly owned subsidiary of Coffeyville Acquisition LLC in order to complete our initial public offering.

Risks Relating to Our Business

We face certain risks that could materially affect our business, results of operations or financial condition. Our petroleum business is primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil; future volatility in refining industry margins may cause volatility or a decline in our results of operations. The current high price of oil has led to a narrowing of crack spreads as a percentage of crude oil prices. As a result, refining margins have not kept pace with the price of oil, and have been further negatively impacted by the Cash Flow Swap. In addition, disruption of our ability to obtain an adequate supply of crude oil could reduce our liquidity and increase our costs.

In addition, our refinery and nitrogen fertilizer facilities face operating hazards and interruptions, including unscheduled maintenance or downtime. The nitrogen fertilizer plant has high fixed costs, and if natural gas prices fall below a certain level, our nitrogen fertilizer business may not generate sufficient revenue to operate profitably. In addition, our operations involve environmental risks that may require us to make substantial capital expenditures to remain in compliance or to remediate current or future contamination that could give rise to material liabilities. Also, we may not recover all of the costs we have incurred in connection with the flood and crude oil discharge that occurred at our refinery on the weekend of June 30, 2007. For more detailed information about the flood and crude oil discharge, including insurance reimbursement information, see Flood and Crude Oil Discharge.

The partnership structure through which we own the nitrogen fertilizer business also involves numerous risks that could materially affect our business. The managing general partner of the Partnership is owned by our controlling stockholders and senior management and manages the operations of the Partnership (subject to our specified joint management rights). The managing general partner owns incentive distribution rights which, over time, will entitle it to receive increasing percentages of quarterly distributions from the Partnership if the Partnership increases its quarterly distributions over a set amount. We are not entitled to cash distributed in respect of the incentive distribution rights. If in the future the managing general partner decides to sell interests in the Partnership, we and you, as a stockholder of CVR Energy, will no longer have access to the cash flows of the Partnership to which the purchasers of these interests will be entitled, and at least 40%

(and potentially all) of our interests will be subordinated to the interests of the new investors. In addition, the managing general partner of the Partnership has a fiduciary duty to favor the interests of its owners, and these interests may differ from our interests and the interests of our stockholders. The members of our senior management also face conflicts of interest because they serve as executive officers of both CVR Energy and the managing general partner of the Partnership.

In May 2008, we restated our consolidated financial statements for the year ended December 31, 2007 and the related quarter ended September 30, 2007 as a result of material weaknesses in our disclosure controls and procedures and internal control over financial reporting. We are in the process of remediating these material weaknesses, but there can be no assurance that we will not in the future identify additional material weaknesses or significant deficiencies in our disclosure controls and procedures or internal control over financial reporting.

For more information about these and other risks relating to our company, see Risk Factors beginning on page 24 and Cautionary Note Regarding Forward-Looking Statements beginning on page 62. You should carefully consider these risk factors together with all other information included in this prospectus.

Table of Contents

Organizational Structure

The following chart illustrates our organizational structure and the organizational structure of the Partnership upon the completion of this offering, assuming the underwriters do not exercise their option to purchase additional shares from certain of the selling stockholders:

* CVR GP, LLC, which we refer to as Fertilizer GP, is the managing general partner of CVR Partners, LP. As managing general partner, Fertilizer GP holds incentive distribution rights, or IDRs, which entitle it to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above an amount specified in the limited partnership agreement. The IDRs will only be payable after the Partnership has distributed all aggregated adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009.

Table of Contents

The Offering

Shares of common stock offered by the selling stockholders	10,000,000 shares.
Option to purchase additional shares of common stock from certain of the selling stockholders	1,500,000 shares.
Common stock outstanding immediately after the offering	86,141,291 shares.
Use of proceeds	We will not receive any proceeds from sales of our common stock by the selling stockholders in this offering.
Dividend policy	We do not anticipate paying any dividends on our common stock in the foreseeable future.
New York Stock Exchange symbol	CVI
Concurrent notes offering	Concurrently with this offering, we are offering $125,000,000 aggregate principal amount of % Convertible Senior Notes due 2013 in a registered public offering. The consummation of this offering is not conditioned upon the concurrent consummation of the convertible notes offering and vice versa.
Risk Factors	See Risk Factors beginning on page 24 of this prospectus for a discussion of factors that you should carefully consider before deciding to invest in shares of our common stock.

The number of shares of common stock outstanding immediately after the offering excludes 7,500,000 shares of common stock issuable under our long-term incentive plan. Of this amount, options to purchase 23,250 shares of common stock have been issued at a weighted average exercise price of $22.23, and 17,500 shares of non-vested restricted stock have been awarded.

CVR Energy, Inc. was incorporated in Delaware in September 2006. Our principal executive offices are located at 2277 Plaza Drive, Suite 500 Sugar Land, Texas 77479, and our telephone number is (281) 207-3200. Our website address is www.cvrenergy.com. Information contained in or linked to or from our website is not a part of this prospectus.

Prior to this offering, Coffeyville Acquisition, an entity owned principally by the Kelso Funds, and Coffeyville Acquisition II, an entity owned principally by the Goldman Sachs Funds, together beneficially owned approximately 73.0% of our capital stock. Coffeyville Acquisition and Coffeyville Acquisition II are, along with our chairman and chief executive officer, selling all of the shares of common stock being sold in this offering. Certain members of our senior management team will receive proceeds from the sale of common stock by Coffeyville Acquisition and

Coffeyville Acquisition II as a result of their membership interest in these entities. Payments will also be made to certain members of our senior management team pursuant to the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) as a direct result of the sale of shares of our common stock by Coffeyville Acquisition and Coffeyville Acquisition II. For further information, see Principal and Selling Stockholders, Certain Relationships and Related Party Transactions and The Nitrogen Fertilizer Limited Partnership.

Depending on market conditions at the time of pricing of this offering and other considerations, the selling stockholders may sell fewer or more shares than the number set forth on the cover page of this prospectus.

Table of Contents

Summary Consolidated Financial Information

The summary consolidated financial information presented below under the caption Statement of Operations Data for the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005 and the years ended December 31, 2006 and 2007, and the summary consolidated financial information presented below under the caption Balance Sheet Data as of December 31, 2006 and 2007, has been derived from our consolidated financial statements included elsewhere in this prospectus, which consolidated financial statements have been audited by KPMG LLP, independent registered public accounting firm. The summary consolidated balance sheet data as of December 31, 2005 is derived from our audited consolidated financial statements that are not included in this prospectus. The summary unaudited interim consolidated financial information presented below under the caption Statement of Operations Data for the three-month period ended March 31, 2007 and the three-month period ended March 31, 2008, and the summary consolidated financial information presented below under the caption Balance Sheet Data as of March 31, 2008, have been derived from our unaudited interim consolidated financial statements, which are included elsewhere in this prospectus and have been prepared on the same basis as the audited consolidated financial statements. In the opinion of management, the interim data reflect all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of results for these periods. Operating results for the three-month period ended March 31, 2008 are not necessarily indicative of the results that may be expected for the year ending December 31, 2008.

We calculate earnings per share for the years ended December 31, 2006 and 2007 and the three-month period ended March 31, 2007 on a pro forma basis, assuming our post-IPO capital structure had been in place for the entire year for each of 2006 and 2007. For the year ended December 31, 2007, 17,500 non-vested common shares and 18,900 common stock options have been excluded from the calculation of pro forma diluted earnings per share because the inclusion of such common stock equivalents in the number of weighted average shares outstanding would be anti-dilutive. We have omitted earnings per share data for 2005 because we operated under a different capital structure than our current capital structure and, therefore, the information is not meaningful.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. See note 1 to our consolidated financial statements included elsewhere in this prospectus. As a result of certain adjustments made in connection with this acquisition, a new basis of accounting was established on the date of the acquisition. Since the assets and liabilities of Successor and Immediate Predecessor were each presented on a new basis of accounting, the financial information for periods before and after June 24, 2005 is not comparable.

On April 23, 2008, the audit committee of our board of directors and management concluded that our previously issued consolidated financial statements for the year ended December 31, 2007 and the related quarter ended September 30, 2007 contained errors. See footnote 2 to our consolidated financial statements for the year ended December 31, 2007 included elsewhere in this prospectus and Management s Discussion and Analysis of Financial Condition and Results of Operations Restatement of Year Ended December 31, 2007 and Quarter Ended September 30, 2007 Financial Statements. All information presented in this prospectus reflects our restated financial results.

Financial data for the 2005 fiscal year is presented as the 174 days ended June 23, 2005 and the 233 days ended December 31, 2005. Coffeyville Acquisition, LLC had no financial statement activity during the period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil, and gasoline option agreements entered into with a related party as of May 16, 2005.

Table of Contents

The historical data presented below has been derived from financial statements that have been prepared using GAAP included elsewhere in this prospectus. This data should be read in conjunction with, and is qualified in its entirety by reference to, the financial statements and related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this prospectus.

	Successor	
	Three Months Ended March 31 2007	Three Months Ended March 31 2008
	(unaudited, in millions, except share and per share data)	
Statement of Operations Data:		
Net sales	$ 390.5	$ 1,223.0
Cost of product sold (exclusive of depreciation and amortization)	303.7	1,036.2
Direct operating expenses (exclusive of depreciation and amortization)	113.4	60.6
Selling, general and administrative expenses (exclusive of depreciation and amortization)	13.2	13.4
Net costs associated with flood(1)		5.8
Depreciation and amortization(2)	14.2	19.6
Operating income (loss)	(54.0)	$ 87.4
Other income, net	0.5	0.9
Interest expense and other financing costs	(11.9)	(11.3)
Loss on derivatives, net	(137.0)	(47.9)
Income (loss) before income taxes and minority interest in subsidiaries	$ (202.4)	$ 29.1
Income tax (expense) benefit	47.3	(6.9)
Minority interest in (income) loss of subsidiaries	0.7	
Net income (loss)(3)	$ (154.4)	$ 22.2
Pro forma loss per share, basic	$ (1.79)	
Pro forma loss per share, diluted	$ (1.79)	
Pro forma weighted average shares, basic	86,141,291	
Pro forma weighted average shares, diluted	86,141,291	
Earnings per share, basic		$ 0.26
Earnings per share, diluted		$ 0.26
Weighted average shares, basic		86,141,291
Weighted average shares, diluted		86,158,791
Segment Financial Data:		
Operating income (loss):		
Petroleum	(63.5)	63.6
Nitrogen Fertilizer	9.3	26.0
Other	0.2	(2.2)
Operating income (loss):	$ (54.0)	$ 87.4

Depreciation and amortization				
Petroleum		9.8		14.9
Nitrogen Fertilizer		4.4		4.5
Other				0.2
Depreciation and amortization(2)	$	14.2	$	19.6
Other Financial Data:				
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	$	(82.4)	$	30.6
Cash flows provided by operating activities		44.1		24.2
Cash flows used in investing activities		(107.4)		(26.2)
Cash flows provided by (used in) financing activities		29.0		(3.4)
Capital expenditures for property, plant and equipment		107.4		26.2

Table of Contents

	Successor Three Months Ended March 31 2007 (unaudited)	Successor Three Months Ended March 31 2008 (unaudited)
Key Operating Statistics:		
Petroleum Business		
Production (barrels per day)(5)	53,689	125,614
Crude oil throughput (barrels per day)(5)	47,267	106,530
Refining margin per crude oil throughput barrel (dollars)(6)	$ 12.69	$ 13.76
NYMEX 2-1-1 crack spread (dollars)(7)	$ 12.17	$ 11.81
Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel (dollars)(8)	$ 22.73	$ 4.16
Gross profit (loss) per crude oil throughput per barrel (dollars)(8)	$ (12.34)	$ 7.50
Nitrogen Fertilizer Business		
Production Volume:		
Ammonia (tons in thousands)	86.2	83.7
UAN (tons in thousands)	165.7	150.1
On-stream factors:		
Gasification	91.8%	91.8%
Ammonia	86.3%	90.7%
UAN	89.4%	85.9%

	Immediate Predecessor 174 Days Ended June 23 2005	Successor 233 Days Ended December 31 2005	Successor Year Ended December 31 2006	Successor Year Ended December 31 2007
	(in millions, except share and per share data)			
Statement of Operations Data:				
Net sales	$ 980.7	$ 1,454.3	$ 3,037.6	$ 2,966.9
Cost of product sold (exclusive of depreciation and amortization)	768.0	1,168.1	2,443.4	2,308.8
Direct operating expenses (exclusive of depreciation and amortization)	80.9	85.3	199.0	276.1
Selling, general and administrative expenses (exclusive of depreciation and amortization)	18.4	18.4	62.6	93.1
Net costs associated with flood(1)				41.5
Depreciation and amortization(2)	1.1	24.0	51.0	60.8
Operating income	$ 112.3	$ 158.5	$ 281.6	$ 186.6
Other income (expense)(9)	(8.4)	0.4	(20.8)	0.2
Interest expense and other financing costs	(7.8)	(25.0)	(43.9)	(61.1)
Gain (loss) on derivatives	(7.6)	(316.1)	94.5	(282.0)

Income (loss) before income taxes	$ 88.5	$ (182.2)	$ 311.4	$ (156.3)
Income tax (expense) benefit	(36.1)	63.0	(119.8)	88.5
Minority interest in (income) loss of subsidiaries				0.2
Net income (loss)(3)	$ 52.4	$ (119.2)	$ 191.6	$ (67.6)
Pro forma earnings per share, basic			$ 2.22	$ (0.78)
Pro forma earnings per share, diluted			$ 2.22	$ (0.78)
Pro forma weighted average shares, basic			86,141,291	86,141,291
Pro forma weighted average shares, diluted			86,158,791	86,141,291

	Immediate Predecessor 174 Days Ended June 23 2005	233 Days Ended December 31 2005	Successor Year Ended December 31 2006	Year Ended December 31 2007
	(in millions, except share and per share data)			
Segment Financial Data:				
Operating income				
Petroleum	76.7	123.0	245.6	144.9
Nitrogen Fertilizer	35.3	35.7	36.8	46.6
Other	0.3	(0.2)	(0.8)	(4.9)
Operating income	112.3	158.5	281.6	186.6
Depreciation and amortization				
Petroleum	0.8	15.6	33.0	43.0
Nitrogen Fertilizer	0.3	8.4	17.1	16.8
Other			0.9	1.0
Depreciation and amortization(2)	1.1	24.0	51.0	60.8
Other Financial Data:				
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	52.4	23.6	115.4	(5.6)
Cash flows provided by operating activities	12.7	82.5	186.6	145.9
Cash flows (used in) investing activities	(12.3)	(730.3)	(240.2)	(268.6)
Cash flows provided by (used in) financing activities	(52.4)	712.5	30.8	111.3
Capital expenditures for property, plant and equipment	12.3	45.2	240.2	268.6

	Immediate Predecessor 174 Days Ended June 23 2005	233 Days Ended December 31 2005	Successor Year Ended December 31 2006 (unaudited)	Year Ended December 31 2007
Key Operating Statistics:				
Petroleum Business				
Production (barrels per day)(5)(10)	99,171	107,177	108,031	86,201
Crude oil throughput (barrels per day)(5)(10)	88,012	93,908	94,524	76,285
Refining margin per crude oil throughput barrel (dollars)(6)	$ 9.28	$ 11.55	$ 13.27	$ 18.17
NYMEX 2-1-1 crack spread (dollars)(7)	9.60	13.47	10.84	13.95
Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel (dollars)(8)	3.44	3.13	3.92	7.52
Gross profit (loss) per crude oil throughput barrel (dollars)(8)	5.79	7.55	8.39	7.79
Nitrogen Fertilizer Business				

Production Volume:				
Ammonia (tons in thousands)(10)	193.2	220.0	369.3	326.7
UAN (tons in thousands)(10)	309.9	353.4	633.1	576.9
On-stream factors(11):				
Gasifier	97.4%	98.7%	92.5%	90.0%
Ammonia	95.0%	98.3%	89.3%	87.7%
UAN	93.9%	94.8%	88.9%	78.7%

Table of Contents

	Successor			
	December 31 2005	December 31 2006	December 31 2007	March 31 2008 (unaudited)
	(in millions)			
Balance Sheet Data:				
Cash and cash equivalents	$ 64.7	$ 41.9	$ 30.5	$ 25.2
Working capital	108.0	112.3	10.7	21.5
Total assets	1,221.5	1,449.5	1,868.4	1,923.6
Total debt, including current portion	499.4	775.0	500.8	499.2
Minority interest in subsidiaries(12)		4.3	10.6	10.6
Divisional/members /stockholders equity	115.8	76.4	432.7	455.1

(1) Represents the write-off of approximate net costs associated with flood and crude oil spill that are not probable of recovery. See Flood and Crude Oil Discharge.

(2) Depreciation and amortization is comprised of the following components as excluded from cost of product sold, direct operating expenses and selling, general and administrative expenses:

	Immediate Predecessor	Successor				
	174 Days Ended June 23 2005	233 Days Ended December 31 2005	Year Ended December 31 2006	Year Ended December 31 2007	Three Months Ended March 31 2007 (unaudited)	Three Months Ended March 31 2008 (unaudited)
	(in millions)					
Depreciation and amortization excluded from cost of product sold	$ 0.1	$ 1.1	$ 2.2	$ 2.4	$ 0.6	$ 0.6
Depreciation and amortization excluded from direct operating expenses	0.9	22.7	47.7	57.4	13.5	18.7
Depreciation and amortization excluded from selling, general and administrative expenses	0.1	0.2	1.1	1.0	0.1	0.3
Depreciation included in net costs associated with flood				7.6		
Total depreciation and amortization	$ 1.1	$ 24.0	$ 51.0	$ 68.4	$ 14.2	$ 19.6

Table of Contents

(3) The following are certain charges and costs incurred in each of the relevant periods that are meaningful to understanding our net income and in evaluating our performance due to their unusual or infrequent nature:

	Immediate Predecessor	Successor				
	174 Days Ended June 23 2005	233 Days Ended December 31 2005	Year Ended December 31 2006	Year Ended December 31 2007	Three Months Ended March 31 2007 (unaudited)	Three Months Ended March 31 2008 (unaudited)
			(in millions)			
Loss on extinguishment of debt(a)	$ 8.1	$	$ 23.4	$ 1.3	$	$
Inventory fair market value adjustment(b)		16.6				
Funded letter of credit expense and interest rate swap not included in interest expense(c)		2.3		1.8		0.9
Major scheduled turnaround expense(d)			6.6	76.4	66.0	
Loss on termination of swap(e)		25.0				
Unrealized (gain) loss from Cash Flow Swap		235.9	(126.8)	103.2	119.7	13.9

(a) Represents the write-off of: (i) $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005, (ii) $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006 and (iii) $1.3 million in connection with the repayment and termination of three credit facilities on October 26, 2007.

(b) Consists of the additional cost of product sold expense due to the step up to estimated fair value of certain inventories on hand at June 24, 2005 as a result of the allocation of the purchase price of the Subsequent Acquisition to inventory.

(c) Consists of fees which are expensed to selling, general and administrative expenses in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. We consider these fees to be equivalent to interest expense and the fees are treated as such in the calculation of EBITDA in the credit facility.

(d) Represents expenses associated with a major scheduled turnaround at the nitrogen fertilizer plant and the refinery.

(e) Represents the expense associated with the expiration of the crude oil, heating oil and gasoline option agreements entered into by Coffeyville Acquisition LLC in May 2005.

(4)

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the unrealized portion of the derivative transaction that was executed in conjunction with the acquisition of Coffeyville Group Holdings, LLC by Coffeyville Acquisition LLC on June 24, 2005. On June 16, 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not as a percentage of crude oil prices) crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through

Table of Contents

December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010, so long as at the time of reduction or termination, we pay the amount of unrealized losses associated with the amount reduced or terminated.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect in each period material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements, which is accounted for as a liability on our balance sheet. As the absolute crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our statement of operations. Conversely, as absolute crack spreads decline we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our board of directors considers our GAAP net income results as well as Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our performance but instead should be utilized as a supplemental measure of financial performance or liquidity in evaluating our business. Because Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our Cash Flow Swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

The following is a reconciliation of Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap to Net income (loss):

	Immediate Predecessor	Successor				
	174 Days Ended June 23 2005	233 Days Ended December 31 2005	Year Ended December 31 2006	Year Ended December 31 2007	Three Months Ended March 31 2007 (unaudited)	Three Months Ended March 31 2008 (unaudited)
	(in millions)					
Net income (loss) adjusted for unrealized gain (loss) from Cash Flow Swap	$ 52.4	$ 23.6	$ 115.4	$ (5.6)	$ (82.4)	$ 30.6
Plus:						

Unrealized gain (loss) from Cash Flow Swap, net of tax benefit		(142.8)	76.2	(62.0)	(72.0)	(8.4)
Net income (loss)	$ 52.4	$ (119.2)	$ 191.6	$ (67.6)	$ (154.4)	$ 22.2

(5) Barrels per day is calculated by dividing the volume in the period by the number of calendar days in the period. Barrels per day as shown here is impacted by plant down-time and other plant disruptions and does not represent the capacity of the facility s continuous operations.

(6) Refining margin per crude oil throughput barrel is a measurement calculated as the difference between net sales and cost of product sold (exclusive of depreciation and amortization) divided by the refinery s crude oil throughput volumes for the respective periods presented. Refining margin per crude oil throughput barrel is a non-GAAP measure that should not be substituted for gross profit or operating income and that we believe is important to investors in evaluating our refinery s performance as a general indication of the amount above our cost of product sold that we are able to sell refined products. Our calculation of refining margin per crude oil throughput barrel may differ from similar calculations of other companies in our industry, thereby limiting its usefulness as a comparative measure. We

use refining margin per crude oil throughput barrel as the most direct and comparable metric to a crack spread which is an observable market indication of industry profitability.

(7) This information is industry data and is not derived from our audited financial statements or unaudited interim financial statements.

(8) Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel is calculated by dividing direct operating expenses (exclusive of depreciation and amortization) by total crude oil throughput volumes for the respective periods presented. Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel includes costs associated with the actual operations of the refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance and labor and environmental compliance costs but does not include depreciation or amortization. We use direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel as a measure of operating efficiency within the plant and as a control metric for expenditures.

Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel is a non-GAAP measure. Our calculations of direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel may differ from similar calculations of other companies in our industry, thereby limiting its usefulness as a comparative measure. The following table reflects direct operating expenses (exclusive of depreciation and amortization) and the related calculation of direct operating expenses per crude oil throughput barrel:

	Immediate Predecessor	Successor				
	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007	Three Months Ended March 31, 2008
			(in millions, except as otherwise indicated)		(unaudited)	(unaudited)
Petroleum Business:						
Net Sales	$ 903.8	$ 1,363.4	$ 2,880.4	$ 2,806.2	$ 352.5	$ 1,168.5
Cost of product sold (exclusive of depreciation and amortization)	761.7	1,156.2	2,422.7	2,300.2	298.5	1,035.1
Direct operating expenses (exclusive of depreciation and amortization)	52.6	56.2	135.3	209.5	96.7	40.3
Net costs associated with flood				36.7		5.5
Depreciation and amortization	0.8	15.6	33.0	43.0	9.8	14.9
Gross profit (loss)	$ 88.7	$ 135.4	$ 289.4	$ 216.8	$ (52.5)	$ 72.7
Plus direct operating expenses (exclusive of	52.6	56.2	135.3	209.5	96.7	40.3

depreciation and amortization)						
Plus net costs associated with flood				36.7		5.5
Plus depreciation and amortization	0.8	15.6	33.0	43.0	9.8	14.9
Refining margin	$ 142.1	$ 207.2	$ 457.7	$ 506.0	$ 54.0	$ 133.4
Refining margin per crude oil throughput barrel (dollars)	$ 9.28	$ 11.55	$ 13.27	$ 18.17	$ 12.69	$ 13.76
Gross profit (loss) per crude oil throughput barrel (dollars)	$ 5.79	$ 7.55	$ 8.39	$ 7.79	$ (12.34)	$ 7.50
Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel (dollars)	$ 3.44	$ 3.13	$ 3.92	$ 7.52	$ 22.73	$ 4.16
Operating income (loss)	76.7	123.0	245.6	144.9	(63.5)	63.6

(9) During the 174 days ended June 23, 2005, the year ended December 31, 2006 and the year ended December 31, 2007, we recognized a loss of $8.1 million, $23.4 million and $1.3 million, respectively, on early extinguishment of debt.

(10) Operational information reflected for the 233 day Successor period ended December 31, 2005 includes only 191 days of operational activity. Successor was formed on May 13, 2005 but had no financial statement activity during the 42 day period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil and gasoline option agreements entered into with J. Aron as of May 16, 2005 which expired unexercised on June 16, 2005.

(11) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period. Excluding the impact of turnaround at the nitrogen fertilizer facility in the third quarter of 2006, the on-stream factors for the year ended December 31, 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN. Excluding the impact of the flood during the weekend of June 30, 2007, the on-stream factors for the year ended December 31, 2007 would have been 94.6% for gasifier, 92.4% for ammonia and 83.9% for UAN.

(12) Minority interest at December 31, 2006 reflects common stock in two of our subsidiaries owned by John J. Lipinski (which were exchanged for shares of our common stock with an equivalent value prior to the consummation of our initial public offering). Minority interest at December 31, 2007 and March 31, 2008 reflects Coffeyville Acquisition III LLC s ownership of the managing general partner interest and IDRs of the Partnership.

Table of Contents

About This Prospectus

Certain Definitions

In this prospectus,

Original Predecessor refers to the former Petroleum Division and one facility within the eight-plant Nitrogen Fertilizer Manufacturing and Marketing Division of Farmland which Coffeyville Resources, LLC acquired on March 3, 2004 in a sales process under Chapter 11 of the U.S. Bankruptcy Code;

Initial Acquisition refers to the acquisition of Original Predecessor on March 3, 2004 by Coffeyville Resources, LLC;

Immediate Predecessor refers to Coffeyville Group Holdings, LLC and its subsidiaries, including Coffeyville Resources, LLC;

Subsequent Acquisition refers to the acquisition of Immediate Predecessor on June 24, 2005 by Coffeyville Acquisition LLC; and

Successor refers to (1) Coffeyville Acquisition LLC and its consolidated subsidiaries from June 24, 2005 through October 15, 2007 and (2) CVR Energy, Inc. and its consolidated subsidiaries (including the Partnership) on and after October 16, 2007.

In addition, in this prospectus:

Managing general partner refers to CVR GP, LLC, the Partnership s managing general partner, which is owned by Coffeyville Acquisition III;

Special general partner refers to CVR Special GP, LLC, the Partnership s special general partner, which is indirectly owned by us;

General Partners refers to the Partnership s managing general partner and special general partner;

Coffeyville Resources refers to Coffeyville Resources, LLC, the subsidiary of CVR Energy which is the sole limited partner of the Partnership;

Coffeyville Acquisition refers to Coffeyville Acquisition LLC, an entity owned principally by the Kelso Funds, which owns 36.5% of our common stock prior to this offering and will own 30.7% of our common stock following this offering, assuming all of the shares of common stock offered hereby are sold and the underwriters do not exercise their option to purchase additional shares;

Coffeyville Acquisition II refers to Coffeyville Acquisition II LLC, an entity owned principally by the Goldman Sachs Funds, which owns 36.5% of our common stock prior to this offering and will own 30.7% of our common stock following this offering, assuming all of the shares of common stock offered hereby are sold and the underwriters do not exercise their option to purchase additional shares; and

Coffeyville Acquisition III refers to Coffeyville Acquisition III LLC, the owner of the Partnership s managing general partner, which in turn is owned by the Goldman Sachs Funds, the Kelso Funds and certain members of CVR Energy s senior management team.

Industry and Market Data

The data included in this prospectus regarding the oil refining industry and the nitrogen fertilizer industry, including trends in the market and our position and the position of our competitors within these industries, are based on our estimates, which have been derived from management s knowledge and experience in the areas in which the relevant businesses operate, and information obtained from customers, distributors, suppliers, trade and business organizations, internal research, publicly available information, industry publications and surveys and other contacts in the areas in which the relevant businesses operate. We have also cited information compiled by industry publications, governmental agencies and publicly available sources. Certain information contained in the Industry section is based on the Energy Information Administration s Annual Energy Outlook 2007, released in May 2007, which is the most recent comprehensive EIA publication currently available. Estimates of market size and relative positions in a market are difficult to develop and inherently uncertain. Accordingly, investors should not place undue weight on the industry and market share data presented in this prospectus.

Trademarks, Trade Names and Service Marks

This prospectus includes trademarks belonging to CVR Energy, Inc., including COFFEYVILLE RESOURCES®, CVR Energy™ and CVR Partners™. This prospectus also contains trademarks, service marks, copyrights and trade names of other companies.

Table of Contents

RISK FACTORS

You should carefully consider each of the following risks and all of the information set forth in this prospectus before deciding to invest in our common stock. If any of the following risks and uncertainties develops into actual events, our business, financial condition or results of operations could be materially adversely affected. In that case, the price of our common stock could decline and you could lose part or all of your investment.

Risks Related to Our Petroleum Business

Volatile margins in the refining industry may cause volatility or a decline in our future results of operations and decrease our cash flow.

Our petroleum business financial results are primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil and other feedstocks. Future volatility in refining industry margins may cause volatility or a decline in our results of operations, since the margin between refined product prices and feedstock prices may decrease below the amount needed for us to generate net cash flow sufficient for our needs. Although an increase or decrease in the price for crude oil generally results in a similar increase or decrease in prices for refined products, there is normally a time lag in the realization of the similar increase or decrease in prices for refined products. The effect of changes in crude oil prices on our results of operations therefore depends in part on how quickly and how fully refined product prices adjust to reflect these changes. A substantial or prolonged increase in crude oil prices without a corresponding increase in refined product prices, or a substantial or prolonged decrease in refined product prices without a corresponding decrease in crude oil prices, could have a significant negative impact on our earnings, results of operations and cash flows. In 2008 we have experienced extremely high oil prices. These high prices have had an adverse effect on the profitability of oil refineries generally, including us. If oil prices remain at their current levels or move higher, our profitability will be materially adversely effected.

If we are required to obtain our crude oil supply without the benefit of our credit intermediation agreement, our exposure to the risks associated with volatile crude prices may increase and our liquidity may be reduced.

We currently obtain the majority of our crude oil supply through a crude oil credit intermediation agreement with J. Aron, which minimizes the amount of in transit inventory and mitigates crude pricing risks by ensuring pricing takes place extremely close to the time when the crude is refined and the yielded products are sold. In the event this agreement is terminated or is not renewed prior to expiration we may be unable to obtain similar services from another party at the same or better terms as our existing agreement. The current credit intermediation agreement expires on December 31, 2008 and will automatically extend for an additional one year term unless either party elects not to extend the agreement. Further, if we were required to obtain our crude oil supply without the benefit of an intermediation agreement, our exposure to crude pricing risks may increase, even despite any hedging activity in which we may engage, and our liquidity would be negatively impacted due to the increased inventory and the negative impact of market volatility.

Our internally generated cash flows and other sources of liquidity may not be adequate for our capital needs.

If we cannot generate adequate cash flow or otherwise secure sufficient liquidity to meet our working capital needs or support our short-term and long-term capital requirements, we may be unable to meet our debt obligations, including payments on the notes, pursue our business strategies or comply with certain environmental standards, which would have a material adverse effect on our business and results of operations. As of March 31, 2008 and June 16, 2008, we had cash, cash equivalents and short-term investments of $25.2 million and $71.4 million, respectively, and up to

Table of Contents

$112.6 million available under our revolving credit facility as of both dates. In the current crude oil price environment, working capital is subject to substantial variability from week-to-week and month-to-month. We have substantial short-term and long-term capital needs. Our short-term working capital needs are primarily crude oil purchase requirements, which fluctuate with the pricing and sourcing of crude oil. In 2008 we have experienced extremely high oil prices which have substantially increased our short-term working capital needs. Our long-term capital needs include capital expenditures we are required to make to comply with Tier II gasoline standards, on-road diesel regulations, off-road diesel regulations and the Consent Decree. We also have significant short-term and long-term needs for cash, including deferred payments of $123.7 million plus accrued interest ($5.8 million as of June 1, 2008) due on August 31, 2008 that are owed under the Cash Flow Swap with J. Aron. We estimate that due to the Cash Flow Swap we also will owe J. Aron approximately $54 million on July 8, 2008 for crude oil we settled or will settle with respect to the quarter ending June 30, 2008, based on June 16, 2008 pricing. Our liquidity and earnings are materially negatively impacted by the effects of the Cash Flow Swap through at least June 2009. See Risks Related to our Entire Business Our commodity derivative activities have historically resulted and in the future could result in losses and in period-to-period earning volatility. In addition, we currently estimate that mandatory capital and turnaround expenditures, excluding the non-recurring capital expenditures required to comply with Tier II gasoline standards, on-road diesel regulations, off-road diesel regulations and the Consent Decree described above, will average approximately $49 million per year over the next five years.

Disruption of our ability to obtain an adequate supply of crude oil could reduce our liquidity and increase our costs.

Our refinery requires approximately 85,000 to 100,000 bpd of crude oil in addition to the light sweet crude oil we gather locally in Kansas, northern Oklahoma and southwest Nebraska. We obtain a portion of our non-gathered crude oil, approximately 22% in 2007, from foreign sources such as Latin America, South America, the Middle East, West Africa, Canada and the North Sea. The actual amount of foreign crude oil we purchase is dependent on market conditions and will vary from year to year. We are subject to the political, geographic, and economic risks attendant to doing business with suppliers located in those regions. Disruption of production in any of such regions for any reason could have a material impact on other regions and our business. In the event that one or more of our traditional suppliers becomes unavailable to us, we may be unable to obtain an adequate supply of crude oil, or we may only be able to obtain our crude oil supply at unfavorable prices. As a result, we may experience a reduction in our liquidity and our results of operations could be materially adversely affected.

Severe weather, including hurricanes along the U.S. Gulf Coast, could interrupt our supply of crude oil. For example, the hurricane season in 2005 produced a record number of named storms, including hurricanes Katrina and Rita. The location and intensity of these storms caused extreme amounts of damage to both crude and natural gas production as well as extensive disruption to many U.S. Gulf Coast refinery operations, although we believe that substantially most of this refining capacity has been restored. These events caused both price spikes in the commodity markets as well as substantial increases in crack spreads in absolute terms. Supplies of crude oil to our refinery are periodically shipped from U.S. Gulf Coast production or terminal facilities, including through the Seaway Pipeline from the U.S. Gulf Coast to Cushing, Oklahoma. U.S. Gulf Coast facilities could be subject to damage or production interruption from hurricanes or other severe weather in the future which could interrupt or materially adversely affect our crude oil supply. If our supply of crude oil is interrupted, our business, financial condition and results of operations could be materially adversely impacted.

Table of Contents

Our profitability is partially linked to the light/heavy and sweet/sour crude oil price spreads. A decrease in either of the spreads would negatively impact our profitability.

Our profitability is partially linked to the price spreads between light and heavy crude oil and sweet and sour crude oil within our plant capabilities. We prefer to refine heavier sour crude oils because they have historically provided wider refining margins than light sweet crude. Accordingly, any tightening of the light/heavy or sweet/sour spreads could reduce our profitability. The light/heavy and sweet/sour spread has declined in recent months, which has resulted, and in the future may continue to result, in a decline in profitability.

The new and redesigned equipment in our facilities may not perform according to expectations, which may cause unexpected maintenance and downtime and could have a negative effect on our future results of operations and financial condition.

During 2007 we upgraded all of the units in our refinery by installing new equipment and redesigning older equipment to improve refinery capacity. The installation and redesign of key equipment involves significant risks and uncertainties, including the following:

- our upgraded equipment may not perform at expected throughput levels;
- the yield and product quality of new equipment may differ from design; and
- redesign or modification of the equipment may be required to correct equipment that does not perform as expected, which could require facility shutdowns until the equipment has been redesigned or modified.

In the second half of 2007 we also repaired certain of our equipment as a result of the flood. This repaired equipment is subject to similar risks and uncertainties as described above. Any of these risks associated with new equipment, redesigned older equipment, or repaired equipment could lead to lower revenues or higher costs or otherwise have a negative impact on our future results of operations and financial condition.

If our access to the pipelines on which we rely for the supply of our feedstock and the distribution of our products is interrupted, our inventory and costs may increase and we may be unable to efficiently distribute our products.

If one of the pipelines on which we rely for supply of our crude oil becomes inoperative, we would be required to obtain crude oil for our refinery through an alternative pipeline or from additional tanker trucks, which could increase our costs and result in lower production levels and profitability. Similarly, if a major refined fuels pipeline becomes inoperative, we would be required to keep refined fuels in inventory or supply refined fuels to our customers through an alternative pipeline or by additional tanker trucks from the refinery, which could increase our costs and result in a decline in profitability.

Our petroleum business financial results are seasonal and generally lower in the first and fourth quarters of the year, which may cause volatility in the price of our common stock.

Demand for gasoline products is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic and road construction work. As a result, our results of operations for the first and fourth calendar quarters are generally lower than for those for the second and third quarters, which may cause volatility in the price of our common stock. Further, reduced agricultural work during the winter months somewhat depresses demand for diesel fuel in the winter months. In addition to the overall seasonality of our business, unseasonably cool weather in the summer months and/or unseasonably warm weather in the winter months in the markets in which we sell our petroleum products could have the effect of reducing demand for gasoline and diesel fuel which could result in lower prices and reduce operating margins.

We face significant competition, both within and outside of our industry. Competitors who produce their own supply of feedstocks, have extensive retail outlets, make alternative fuels or have greater financial resources than we do may have a competitive advantage over us.

The refining industry is highly competitive with respect to both feedstock supply and refined product markets. We may be unable to compete effectively with our competitors within and outside of our industry, which could result in reduced profitability. We compete with numerous other companies for available supplies of crude oil and other feedstocks and for outlets for our refined products. We are not engaged in the petroleum exploration and production business and therefore we do not produce any of our crude oil feedstocks. We do not have a retail business and therefore are dependent upon others for outlets for our refined products. We do not have any long-term arrangements for much of our output. Many of our competitors in the United States as a whole, and one of our regional competitors, obtain significant portions of their feedstocks from company-owned production and have extensive retail outlets. Competitors that have their own production or extensive retail outlets with brand-name recognition are at times able to offset losses from refining operations with profits from producing or retailing operations, and may be better positioned to withstand periods of depressed refining margins or feedstock shortages.

A number of our competitors also have materially greater financial and other resources than us, providing them the ability to add incremental capacity in environments of high crack spreads. These competitors have a greater ability to bear the economic risks inherent in all phases of the refining industry. An expansion or upgrade of our competitors facilities, price volatility, international political and economic developments and other factors are likely to continue to play an important role in refining industry economics and may add additional competitive pressure on us.

In addition, we compete with other industries that provide alternative means to satisfy the energy and fuel requirements of our industrial, commercial and individual consumers. The more successful these alternatives become as a result of governmental regulations, technological advances, consumer demand, improved pricing or otherwise, the greater the impact on pricing and demand for our products and our profitability. There are presently significant governmental and consumer pressures to increase the use of alternative fuels in the United States.

Environmental laws and regulations will require us to make substantial capital expenditures in the future.

Current or future federal, state and local environmental laws and regulations could cause us to spend substantial amounts to install controls or make operational changes to comply with environmental requirements. In addition, future environmental laws and regulations, or new interpretations of existing laws or regulations, could limit our ability to market and sell our products to end users. Any such new interpretations or future environmental laws or governmental regulations could have a material impact on the results of our operations.

In March 2004, we entered into a Consent Decree with the United States Environmental Protection Agency, or the EPA, and the Kansas Department of Health and Environment, or the KDHE, to address certain allegations of Clean Air Act violations by Farmland at the Coffeyville oil refinery in order to address the alleged violations and eliminate liabilities going forward. The overall costs of complying with the Consent Decree over the next four years are expected to be approximately $41 million. To date, we have met the deadlines and requirements of the Consent Decree and we have not had to pay any stipulated penalties, which are required to be paid for failure to comply with various terms and conditions of the Consent Decree. Availability of equipment and technology performance, as well as EPA interpretations of provisions of the Consent Decree that differ from ours, could affect our ability to meet the requirements imposed by the Consent Decree and have a material adverse effect on our results of operations, financial condition and profitability.

We may agree to enter into a global settlement under EPA s National Petroleum Refining Initiative, or the NPRI. The 2004 Consent Decree addressed two of the four marquee issues under

Table of Contents

the NPRI. We may agree to enter into a new consent decree or amend the existing Consent Decree to incorporate the marquee issues that were not addressed in the 2004 consent decree. We do not believe that addressing the remaining marquee issues would have a material adverse effect on our results of operations, financial condition and profitability.

We will incur capital expenditures over the next several years in order to comply with regulations under the federal Clean Air Act establishing stringent low sulfur content specifications for our petroleum products, including the Tier II gasoline standards, as well as regulations with respect to on- and off-road diesel fuel, which are designed to reduce air emissions from the use of these products. In February 2004, the EPA granted us a hardship waiver, which will require us to meet final low sulfur Tier II gasoline standards by January 1, 2011. In 2007, as a result of the flood, our refinery exceeded the average annual gasoline sulfur standard mandated by the hardship waiver. We are re-negotiating provisions of the hardship waiver and have agreed in principle to meet the final low sulfur Tier II gasoline sulfur standards by January 1, 2010 (one year earlier than required under the hardship waiver) in consideration for the EPA s agreement not to seek a penalty for the 2007 sulfur exceedance. Compliance with the Tier II gasoline standards and on-road diesel standards required us to spend approximately $133 million during 2006 and approximately $103 million during 2007, and we estimate that compliance will require us to spend approximately $68 million between 2008 and 2010. Changes in equipment or construction costs could require significantly greater expenditures.

Changes in our credit profile may affect our relationship with our suppliers, which could have a material adverse effect on our liquidity.

Changes in our credit profile may affect the way crude oil suppliers view our ability to make payments and may induce them to shorten the payment terms of their invoices. Given the large dollar amounts and volume of our feedstock purchases, a change in payment terms may have a material adverse effect on our liquidity and our ability to make payments to our suppliers.

Risks Related to the Nitrogen Fertilizer Business

Natural gas prices affect the price of the nitrogen fertilizers that the nitrogen fertilizer business sells. Any decline in natural gas prices could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Because most nitrogen fertilizer manufacturers rely on natural gas as their primary feedstock, and the cost of natural gas is a large component (approximately 90% based on historical data) of the total production cost of nitrogen fertilizers for natural gas-based nitrogen fertilizer manufacturers, the price of nitrogen fertilizers has historically generally correlated with the price of natural gas. We are currently in a period of high natural gas prices, and the price at which the nitrogen fertilizer business is able to sell its nitrogen fertilizers is near historical highs. However, natural gas prices are cyclical and volatile and may decline at any time. The nitrogen fertilizer business does not hedge against declining natural gas prices. Any decline in natural gas prices could have a material adverse impact on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The nitrogen fertilizer plant has high fixed costs. If nitrogen fertilizer product prices fall below a certain level, which could be caused by a reduction in the price of natural gas, the nitrogen fertilizer business may not generate sufficient revenue to operate profitably or cover its costs.

The nitrogen fertilizer plant has high fixed costs as discussed in Management s Discussion and Analysis of Financial Condition and Results of Operations Major Influences on Results of Operations Nitrogen Fertilizer Business. As a result, downtime or low productivity due to reduced demand, interruptions because of adverse weather conditions, equipment failures, low prices for

28

nitrogen fertilizer or other causes can result in significant operating losses. Unlike its competitors, whose primary costs are related to the purchase of natural gas and whose fixed costs are minimal, the nitrogen fertilizer business has high fixed costs not dependent on the price of natural gas. We have no control over natural gas prices, which can be highly volatile. A decline in natural gas prices generally has the effect of reducing the base sale price for nitrogen fertilizer products in the market generally while the nitrogen fertilizer business fixed costs will remain substantially unchanged by the decline in natural gas prices. Any decline in the price of nitrogen fertilizer products could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The demand for and pricing of nitrogen fertilizers have increased dramatically in recent years. The nitrogen fertilizer business is cyclical and volatile and historically, periods of high demand and pricing have been followed by periods of declining prices and declining capacity utilization. Such cycles expose us to potentially significant fluctuations in our financial condition, cash flows and results of operations, which could result in volatility in the price of our common stock or an inability of the nitrogen fertilizer business to make quarterly distributions.

A significant portion of nitrogen fertilizer product sales consists of sales of agricultural commodity products, exposing us to fluctuations in supply and demand in the agricultural industry. These fluctuations historically have had and could in the future have significant effects on prices across all nitrogen fertilizer products and, in turn, the nitrogen fertilizer business financial condition, cash flows and results of operations, which could result in significant volatility in the price of our common stock or an inability of the nitrogen fertilizer business to make distributions to us. Nitrogen fertilizer products are commodities, the price of which can be volatile. The prices of nitrogen fertilizer products depend on a number of factors, including general economic conditions, cyclical trends in end-user markets, supply and demand imbalances, and weather conditions, which have a greater relevance because of the seasonal nature of fertilizer application. If seasonal demand exceeds the projections of the nitrogen fertilizer business, its customers may acquire nitrogen fertilizer from its competitors, and the profitability of the nitrogen fertilizer business will be negatively impacted. If seasonal demand is less than expected, the nitrogen fertilizer business will be left with excess inventory that will have to be stored or liquidated.

Demand for fertilizer products is dependent, in part, on demand for crop nutrients by the global agricultural industry. Nitrogen-based fertilizers are currently in high demand, driven by a growing world population, changes in dietary habits and an expanded use of corn for the production of ethanol. Supply is affected by available capacity and operating rates, raw material costs, government policies and global trade. The prices for nitrogen fertilizers are currently extremely high. Nitrogen fertilizer prices may not remain at current levels and could fall, perhaps materially. A decrease in nitrogen fertilizer prices would have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Nitrogen fertilizer products are global commodities, and the nitrogen fertilizer business faces intense competition from other nitrogen fertilizer producers.

The nitrogen fertilizer business is subject to intense price competition from both U.S. and foreign sources, including competitors operating in the Persian Gulf, the Asia-Pacific region, the Caribbean, Russia and Ukraine. Nitrogen fertilizer products are global commodities, with little or no product differentiation, and customers make their purchasing decisions principally on the basis of delivered price and availability of the product. The nitrogen fertilizer business competes with a number of U.S. producers and producers in other countries, including state-owned and government-subsidized entities. The United States and the European Union each have trade regulatory measures in effect that are designed to address this type of unfair trade, but there is no guarantee that such trade regulatory measures will continue. Changes in these measures could have a material adverse impact on the sales and profitability of the particular products involved. Some competitors have greater total

resources and are less dependent on earnings from fertilizer sales, which makes them less vulnerable to industry downturns and better positioned to pursue new expansion and development opportunities. In addition, recent consolidation in the fertilizer industry has increased the resources of several competitors. In light of this industry consolidation, our competitive position could suffer to the extent the nitrogen fertilizer business is not able to expand its own resources either through investments in new or existing operations or through acquisitions, joint ventures or partnerships. In addition, if natural gas prices in the United States were to decline to a level that prompts those U.S. producers who have previously closed production facilities to resume fertilizer production, this would likely contribute to a global supply/demand imbalance that could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. An inability to compete successfully could result in the loss of customers, which could adversely affect our sales and profitability.

Adverse weather conditions during peak fertilizer application periods may have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions, because the agricultural customers of the nitrogen fertilizer business are geographically concentrated.

Sales of nitrogen fertilizer products by the nitrogen fertilizer business to agricultural customers are concentrated in the Great Plains and Midwest states and are seasonal in nature. For example, the nitrogen fertilizer business generates greater net sales and operating income in the spring. Accordingly, an adverse weather pattern affecting agriculture in these regions or during this season including flooding could have a negative effect on fertilizer demand, which could, in turn, result in a material decline in our net sales and margins and otherwise have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. Our quarterly results may vary significantly from one year to the next due primarily to weather-related shifts in planting schedules and purchase patterns.

The nitrogen fertilizer business results of operations, financial condition and ability to make cash distributions may be adversely affected by the supply and price levels of pet coke and other essential raw materials.

Pet coke is a key raw material used by the nitrogen fertilizer business in the manufacture of nitrogen fertilizer products. Increases in the price of pet coke could have a material adverse effect on the nitrogen fertilizer business results of operations, financial condition and ability to make cash distributions. Moreover, if pet coke prices increase the nitrogen fertilizer business may not be able to increase its prices to recover increased pet coke costs, because market prices for the nitrogen fertilizer business nitrogen fertilizer products are generally correlated with natural gas prices, the primary raw material used by competitors of the nitrogen fertilizer business, and not pet coke prices. Based on the nitrogen fertilizer business current output, the nitrogen fertilizer business obtains most (over 75% on average during the last four years) of the pet coke it needs from our adjacent oil refinery, and procures the remainder on the open market. The nitrogen fertilizer business competitors are not subject to changes in pet coke prices. The nitrogen fertilizer business is sensitive to fluctuations in the price of pet coke on the open market. Pet coke prices could significantly increase in the future. The nitrogen fertilizer business might also be unable to find alternative suppliers to make up for any reduction in the amount of pet coke it obtains from our oil refinery.

The nitrogen fertilizer business may not be able to maintain an adequate supply of pet coke and other essential raw materials. In addition, the nitrogen fertilizer business could experience production delays or cost increases if alternative sources of supply prove to be more expensive or difficult to obtain. If raw material costs were to increase, or if the nitrogen fertilizer plant were to experience an extended interruption in the supply of raw materials, including pet coke, to its production facilities, the nitrogen fertilizer business could lose sale opportunities, damage its relationships with or lose

customers, suffer lower margins, and experience other material adverse effects to its results of operations, financial condition and ability to make cash distributions.

The nitrogen fertilizer business relies on an air separation plant owned by The Linde Group to provide oxygen, nitrogen and compressed dry air to its gasifier. A deterioration in the financial condition of The Linde Group, or a mechanical problem with the air separation plant, could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The nitrogen fertilizer business relies on an air separation plant owned by The Linde Group, or Linde, to provide oxygen, nitrogen and compressed dry air to its gasifier. The nitrogen fertilizer business operations could be adversely affected if there were a deterioration in Linde s financial condition such that the operation of the air separation plant were disrupted. Additionally, this air separation plant in the past has experienced numerous momentary interruptions, thereby causing interruptions in the nitrogen fertilizer business gasifier operations. The nitrogen fertilizer business requires a reliable supply of oxygen, nitrogen and compressed dry air. A disruption of its supply could prevent it from producing its products at current levels and could have a material adverse effect on our results of operations, financial condition and ability of the nitrogen fertilizer business to make cash distributions.

Ammonia can be very volatile and dangerous. Any liability for accidents involving ammonia that cause severe damage to property and/or injury to the environment and human health could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. In addition, the costs of transporting ammonia could increase significantly in the future.

The nitrogen fertilizer business manufactures, processes, stores, handles, distributes and transports ammonia, which can be very volatile and dangerous. Accidents, releases or mishandling involving ammonia could cause severe damage or injury to property, the environment and human health, as well as a possible disruption of supplies and markets. Such an event could result in lawsuits, fines, penalties and regulatory enforcement proceedings, all of which could lead to significant liabilities. Any damage to persons, equipment or property or other disruption of the ability of the nitrogen fertilizer business to produce or distribute its products could result in a significant decrease in operating revenues and significant additional cost to replace or repair and insure its assets, which could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. The nitrogen fertilizer business experienced an ammonia release most recently in August 2007. See Business Environmental Matters Release Reporting.

In addition, the nitrogen fertilizer business may incur significant losses or costs relating to the operation of railcars used for the purpose of carrying various products, including ammonia. Due to the dangerous and potentially toxic nature of the cargo, in particular ammonia, a railcar accident may have catastrophic results, including fires, explosions and pollution. These circumstances may result in severe damage and/or injury to property, the environment and human health. In the event of pollution, the nitrogen fertilizer business may be strictly liable. If the nitrogen fertilizer business is strictly liable, it could be held responsible even if it is not at fault and complied with the laws and regulations in effect at the time of the accident. Litigation arising from accidents involving ammonia may result in the Partnership or us being named as a defendant in lawsuits asserting claims for large amounts of damages, which could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Given the risks inherent in transporting ammonia, the costs of transporting ammonia could increase significantly in the future. Ammonia is typically transported by railcar. A number of initiatives are underway in the railroad and chemical industries that may result in changes to railcar design in order to minimize railway accidents involving hazardous materials. If any such design changes are

implemented, or if accidents involving hazardous freight increases the insurance and other costs of railcars, freight costs of the nitrogen fertilizer business could significantly increase.

The nitrogen fertilizer business operations are dependent on a limited number of third-party suppliers. Failure by key suppliers of oxygen, nitrogen and electricity to perform in accordance with their contractual obligations may have a negative effect upon our results of operations and financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The nitrogen fertilizer operations depend in large part on the performance of third-party suppliers, including Linde for the supply of oxygen and nitrogen and the city of Coffeyville for the supply of electricity. The contract with Linde extends through 2020 and the electricity contract extends through 2019. Should these suppliers fail to perform in accordance with the existing contractual arrangements, the nitrogen fertilizer business operations would be forced to a halt. Alternative sources of supply of oxygen, nitrogen or electricity could be difficult to obtain. Any shutdown of operations at the nitrogen fertilizer business even for a limited period could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The nitrogen fertilizer business relies on third party providers of transportation services and equipment, which subjects us to risks and uncertainties beyond our control that may have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The nitrogen fertilizer business relies on railroad and trucking companies to ship nitrogen fertilizer products to its customers. The nitrogen fertilizer business also leases rail cars from rail car owners in order to ship its products. These transportation operations, equipment, and services are subject to various hazards, including extreme weather conditions, work stoppages, delays, spills, derailments and other accidents and other operating hazards.

These transportation operations, equipment and services are also subject to environmental, safety, and regulatory oversight. Due to concerns related to terrorism or accidents, local, state and federal governments could implement new regulations affecting the transportation of the nitrogen fertilizers business products. In addition, new regulations could be implemented affecting the equipment used to ship its products.

Any delay in the nitrogen fertilizer businesses ability to ship its products as a result of these transportation companies failure to operate properly, the implementation of new and more stringent regulatory requirements affecting transportation operations or equipment, or significant increases in the cost of these services or equipment, could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Environmental laws and regulations on fertilizer end-use and application could have a material adverse impact on fertilizer demand in the future.

Future environmental laws and regulations on the end-use and application of fertilizers could cause changes in demand for the nitrogen fertilizer business products. In addition, future environmental laws and regulations, or new interpretations of existing laws or regulations, could limit the ability of the nitrogen fertilizer business to market and sell its products to end users. From time to time, various state legislatures have proposed bans or other limitations on fertilizer products. Any such future laws, regulations or interpretations could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Table of Contents

A major factor underlying the current high level of demand for nitrogen-based fertilizer products is the expanding production of ethanol. A decrease in ethanol production, an increase in ethanol imports or a shift away from corn as a principal raw material used to produce ethanol could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

A major factor underlying the current high level of demand for nitrogen-based fertilizer products is the expanding production of ethanol in the United States and the expanded use of corn in ethanol production. Ethanol production in the United States is highly dependent upon a myriad of federal and state legislation and regulations, and is made significantly more competitive by various federal and state incentives. Such incentive programs may not be renewed, or if renewed, they may be renewed on terms significantly less favorable to ethanol producers than current incentive programs. Recent studies showing that expanded ethanol production may increase the level of greenhouse gases in the environment may reduce political support for ethanol production. The elimination or significant reduction in ethanol incentive programs could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Imported ethanol is generally subject to a $0.54 per gallon tariff and a 2.5% ad valorem tax. This tariff is set to expire on December 31, 2008. This tariff may not be renewed, or if renewed, it may be renewed on terms significantly less favorable for domestic ethanol production than current incentive programs. We do not know the extent to which the volume of imports would increase or the effect on U.S. prices for ethanol if the tariff is not renewed beyond its current expiration. The elimination of tariffs on imported ethanol may negatively impact the demand for domestic ethanol, which could lower U.S. corn and other grain production and thereby have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Most ethanol is currently produced from corn and other raw grains, such as milo or sorghum especially in the Midwest. The current trend in ethanol production research is to develop an efficient method of producing ethanol from cellulose-based biomass, such as agricultural waste, forest residue, municipal solid waste and energy crops (plants grown for use to make biofuels or directly exploited for the energy content). This trend is driven by the fact that cellulose-based biomass is generally cheaper than corn, and producing ethanol from cellulose-based biomass would create opportunities to produce ethanol in areas that are unable to grow corn. Although current technology is not sufficiently efficient to be competitive, new conversion technologies may be developed in the future. If an efficient method of producing ethanol from cellulose-based biomass is developed, the demand for corn may decrease, which could reduce demand for the nitrogen fertilizer business products, which could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

If global transportation costs decline, the nitrogen fertilizer business competitors may be able to sell their products at a lower price, which would have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Many of the nitrogen fertilizer business competitors produce fertilizer outside of the U.S. farm belt region and incur costs in transporting their products to this region via ships and pipelines. There can be no assurance that competitors transportation costs will not decline or that additional pipelines will not be built, lowering the price at which the nitrogen fertilizer business competitors can sell their products, which would have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

Table of Contents

Risks Related to Our Entire Business

Our refinery and nitrogen fertilizer facilities face operating hazards and interruptions, including unscheduled maintenance or downtime. We could face potentially significant costs to the extent these hazards or interruptions are not fully covered by our existing insurance coverage. Insurance companies that currently insure companies in the energy industry may cease to do so or may substantially increase premiums in the future.

Our operations, located primarily in a single location, are subject to significant operating hazards and interruptions. If any of our facilities, including our refinery and the nitrogen fertilizer plant, experiences a major accident or fire, is damaged by severe weather, flooding or other natural disaster, or is otherwise forced to curtail its operations or shut down, we could incur significant losses which could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. In addition, a major accident, fire, flood, crude oil discharge or other event could damage our facilities or the environment and the surrounding community or result in injuries or loss of life. For example, the flood that occurred during the weekend of June 30, 2007 shut down our refinery for seven weeks, shut down the nitrogen fertilizer -facility for approximately two weeks and required significant expenditures to repair damaged equipment.

If our facilities experience a major accident or fire or other event or an interruption in supply or operations, our business could be materially adversely affected if the damage or liability exceeds the amounts of business interruption, property, terrorism and other insurance that we benefit from or maintain against these risks and successfully collect. As required under our existing credit facility, we maintain property and business interruption insurance capped at $1.25 billion which is subject to various deductibles and sub-limits for particular types of coverage (e.g., $300 million for a loss caused by flood). In the event of a business interruption, we would not be entitled to recover our losses until the interruption exceeds 45 days in the aggregate. We are fully exposed to losses in excess of this dollar cap and the various sub-limits, or business interruption losses that occur in the 45 days of our deductible period. These losses may be material. For example, a substantial portion of our lost revenue caused by the business interruption following the flood that occurred during the weekend of June 30, 2007 cannot be claimed because it was lost within 45 days of the start of the flood.

If our refinery is forced to curtail its operations or shut down due to hazards or interruptions like those described above, we will still be obligated to make any required payments to J. Aron under certain swap agreements we entered into in June 2005 (as amended, the Cash Flow Swap). We will be required to make payments under the Cash Flow Swap if crack spreads in absolute terms rise above a certain level. Such payments could have a material adverse impact on our financial results if, as a result of a disruption to our operations, we are unable to sustain sufficient revenues from which we can make such payments.

The energy industry is highly capital intensive, and the entire or partial loss of individual facilities can result in significant costs to both industry participants, such as us, and their insurance carriers. In recent years, several large energy industry claims have resulted in significant increases in the level of premium costs and deductible periods for participants in the energy industry. For example, during 2005, Hurricanes Katrina and Rita caused significant damage to several petroleum refineries along the U.S. Gulf Coast, in addition to numerous oil and gas production facilities and pipelines in that region. As a result of large energy industry claims, insurance companies that have historically participated in underwriting energy related facilities could discontinue that practice, or demand significantly higher premiums or deductibles to cover these facilities. Although we currently maintain significant amounts of insurance, insurance policies are subject to annual renewal. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost or we might need to significantly increase our retained exposures.

Our refinery consists of a number of processing units, many of which have been in operation for a number of years. One or more of the units may require unscheduled down time for unanticipated maintenance or repairs on a more frequent basis than our scheduled turnaround of every three to four years for each unit, or our planned turnarounds may last longer than anticipated. The nitrogen fertilizer plant, or individual units within the plant, will require scheduled or unscheduled downtime for maintenance or repairs. In general, the nitrogen fertilizer facility requires scheduled turnaround maintenance every two years and the next scheduled turnaround is currently expected to occur in the fourth quarter of 2008. Scheduled and unscheduled maintenance could reduce net income and cash flow during the period of time that any of our units is not operating.

Our commodity derivative activities have historically resulted and in the future could result in losses and in period-to-period earnings volatility.

The nature of our operations results in exposure to fluctuations in commodity prices. If we do not effectively manage our derivative activities, we could incur significant losses. We monitor our exposure and, when appropriate, utilize derivative financial instruments and physical delivery contracts to mitigate the potential impact from changes in commodity prices. If commodity prices change from levels specified in our various derivative agreements, a fixed price contract or an option price structure could limit us from receiving the full benefit of commodity price changes. In addition, by entering into these derivative activities, we may suffer financial loss if we do not produce oil to fulfill our obligations. In the event we are required to pay a margin call on a derivative contract, we may be unable to benefit fully from an increase in the value of the commodities we sell. In addition, we may be required to make a margin payment before we are able to realize a gain on a sale resulting in a reduction in cash flow, particularly if prices decline by the time we are able to sell.

In June 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap, which is not subject to margin calls, in the form of three swap agreements with J. Aron for the period from July 1, 2005 to June 30, 2010. These agreements were subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. Based on crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010. Otherwise, under the terms of our credit facility, management has limited discretion to change the amount of hedged volumes under the Cash Flow Swap therefore affecting our exposure to market volatility. The current environment of high and rising crude oil prices has led to higher crack spreads in absolute terms but significantly narrower crack spreads as a percentage of crude oil prices. As a result, the Cash Flow Swap, under which payments are calculated based on crack spreads in absolute terms, has had and will continue to have a material negative impact on our earnings. In addition, because this derivative is based on NYMEX prices while our revenue is based on prices in the Coffeyville supply area, the contracts do not eliminate risk of price volatility. If the price of products on NYMEX is different from the value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product that is contracted in the swap. We have substantial payment obligations to J. Aron in respect of the Cash Flow Swap. See Our internally generated cash flows and other sources of liquidity may not be adequate for our capital needs.

In addition, as a result of the accounting treatment of these contracts, unrealized gains and losses are charged to our earnings based on the increase or decrease in the market value of the unsettled position and the inclusion of such derivative gains or losses in earnings may produce significant period-to-period earnings volatility that is not necessarily reflective of our underlying operating performance. The positions under the Cash Flow Swap resulted in unrealized gains (losses) of $126.8 million, $(103.2) million and $(13.9) million for the years ended December 31, 2006 and

Table of Contents

2007 and the three months ended March 31, 2008, respectively. The positions under the Cash Flow Swap had a significant negative impact on our earnings in 2007 and are expected to continue to do so in 2008. As of March 31, 2008, a $1.00 change in quoted prices for the absolute crack spreads utilized in the Cash Flow Swap would result in a $36.2 million change to the fair value of derivative commodity position and the same change to net income. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Derivative Instruments and Fair Value of Financial Instruments.

We may not recover all of the costs we have incurred in connection with the flood and crude oil discharge that occurred at our refinery in June/July 2007.

We have incurred significant costs with respect to facility repairs, environmental remediation and property damage claims.

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville, Kansas. Our refinery and nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required extensive repairs. Total gross costs incurred and recorded as of March 31, 2008 related to the third party costs to repair the refinery and fertilizer facilities were approximately $82.5 million and $4.0 million, respectively. Additionally, other corporate overhead and miscellaneous costs incurred and recorded in connection with the flood as of March 31, 2008 were approximately $19.3 million. We currently estimate that approximately $2.1 million in third party costs related to the repair of flood damaged property will be recorded in future periods. In addition to the cost of repairing the facilities, we experienced a significant revenue loss attributable to the property damage during the period when the facilities were not in operation.

Despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. We expect to substantially complete remediation of the contamination caused by the crude oil discharge by July 31, 2008 and anticipate minor remediation activities thereafter. Total net costs recorded as of March 31, 2008 associated with remediation efforts and third party property damage incurred by the crude oil discharge are approximately $27.3 million. This amount is net of anticipated insurance recoveries of $21.4 million.

As of March 31, 2008, we have recorded total gross costs associated with the repair of, and other matters relating to the damage to our facilities and with third party and property damage remediation incurred due to the crude oil discharge of approximately $154.5 million. Total anticipated insurance recoveries of approximately $107.2 million have been recorded as March 31, 2008 (of which $21.5 million has already been received from insurance carriers by us), resulting in a net cost of approximately $47.3 million. We have not estimated any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from lawsuits related to the flood.

The ultimate cost of environmental remediation and third party property damage is difficult to assess and could be higher than our current estimates.

It is difficult to estimate the ultimate cost of environmental remediation resulting from the crude oil discharge or the cost of third party property damage that we will ultimately be required to pay. The costs and damages that we ultimately pay may be greater than the estimated amounts currently described in our filings with the Securities and Exchange Commission (the SEC). Such excess costs and damages could be material.

We do not know which of our losses our insurers will ultimately cover or when we will receive any insurance recovery.

During the time of the 2007 flood and crude oil discharge, Coffeyville Resources, LLC was covered by both property/business interruption and liability insurance policies. We are in the process of submitting claims to, responding to information requests from, and negotiating with various insurers with respect to costs and damages related to these incidents. However, we do not know which of our losses, if any, the insurers will ultimately cover or when we will receive any recovery. We may not be able to recover all of the costs we have incurred and losses we have suffered in connection with the 2007 flood and crude oil discharge. Further, we likely will not be able to recover most of the business interruption losses we incurred since a substantial portion of our facilities were operational within 45 days of the start of the flood, and our coverage for business interruption losses applies only if the facilities were not operational for 45 days or more.

Environmental laws and regulations could require us to make substantial capital expenditures to remain in compliance or to remediate current or future contamination that could give rise to material liabilities.

Our operations are subject to a variety of federal, state and local environmental laws and regulations relating to the protection of the environment, including those governing the emission or discharge of pollutants into the environment, product specifications and the generation, treatment, storage, transportation, disposal and remediation of solid and hazardous waste and materials. Environmental laws and regulations that affect our operations and processes and the margins for our refined products are extensive and have become progressively more stringent. Violations of these laws and regulations or permit conditions can result in substantial penalties, injunctive relief requirements compelling installation of additional controls, civil and criminal sanctions, permit revocations and/or facility shutdowns.

In addition, new environmental laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement of laws and regulations or other developments could require us to make additional unforeseen expenditures. Many of these laws and regulations are becoming increasingly stringent, and the cost of compliance with these requirements can be expected to increase over time. The requirements to be met, as well as the technology and length of time available to meet those requirements, continue to develop and change. These expenditures or costs for environmental compliance could have a material adverse effect on our results of operations, financial condition and profitability.

Our business is inherently subject to accidental spills, discharges or other releases of petroleum or hazardous substances into the environment and neighboring areas. Past or future spills related to any of our operations, including our refinery, pipelines, product terminals, fertilizer plant or transportation of products or hazardous substances from those facilities, may give rise to liability (including strict liability, or liability without fault, and potential cleanup responsibility) to governmental entities or private parties under federal, state or local environmental laws, as well as under common law. For example, we could be held strictly liable under the Comprehensive Environmental Responsibility, Compensation and Liability Act, or CERCLA, for past or future spills without regard to fault or whether our actions were in compliance with the law at the time of the spills. Pursuant to CERCLA and similar state statutes, we could be held liable for contamination associated with facilities we currently own or operate, facilities we formerly owned or operated and facilities to which we transported or arranged for the transportation of wastes or by-products containing hazardous substances for treatment, storage, or disposal. In addition, we face liability for alleged personal injury or property damage due to exposure to chemicals or other hazardous substances located at or released from our facilities. We may also face liability for personal injury, property damage, natural resource damage or for cleanup costs for the alleged migration of contamination or other hazardous substances from our facilities to adjacent and other nearby properties.

Two of our facilities, including our Coffeyville oil refinery and the Phillipsburg terminal (which operated as a refinery until 1991), have environmental contamination. We have assumed Farmland s responsibilities under certain Resource Conservation and Recovery Act, or RCRA, corrective action

orders related to contamination at or that originated from the refinery (which includes portions of the nitrogen fertilizer plant) and the Phillipsburg terminal. If significant unknown liabilities that have been undetected to date by our extensive soil and groundwater investigation and sampling programs arise in the areas where we have assumed liability for the corrective action, that liability could have a material adverse effect on our results of operations and financial condition and may not be covered by insurance.

For a discussion of environmental risks and impacts related to the 2007 flood and crude oil discharge, see We may not recover all of the costs we have incurred in connection with the flood and crude oil discharge that occurred at our refinery in June/July 2007.

CO_2 and other greenhouse gas emissions may be the subject of federal or state legislation or regulated in the future by the EPA as an air pollutant, requiring us to obtain additional permits, install additional controls, or purchase credits to reduce greenhouse gas emissions which could adversely affect our financial performance.

The United States Congress has considered various proposals to reduce greenhouse gas emissions, but none have become law, and presently, there are no federal mandatory greenhouse gas emissions requirements. While it is probable that Congress will adopt some form of federal mandatory greenhouse gas emission reductions legislation in the future, the timing and specific requirements of any such legislation are uncertain at this time. In the absence of existing federal regulations, a number of states have adopted regional greenhouse gas initiatives to reduce CO_2 and other greenhouse gas emissions. In 2007, a group of Midwest states, including Kansas (where our refinery and the nitrogen fertilizer facility are located) formed the Midwestern Greenhouse Gas Accord, which calls for the development of a cap-and-trade system to control greenhouse gas emissions and for the inventory of such emissions. However, the individual states that have signed on to the accord must adopt laws or regulations implementing the trading scheme before it becomes effective, and the timing and specific requirements of any such laws or regulations in Kansas are uncertain at this time.

In 2007, the U.S. Supreme Court decided that CO_2 is an air pollutant under the federal Clean Air Act for the purposes of vehicle emissions. Similar lawsuits have been filed seeking to require the EPA to regulate CO_2 emissions from stationary sources, such as our refinery and the fertilizer plant, under the federal Clean Air Act. Our refinery and the nitrogen fertilizer plant produce significant amounts of CO_2 that are vented into the atmosphere. If the EPA regulates CO_2 emissions from facilities such as ours, we may have to apply for additional permits, install additional controls to reduce CO_2 emissions or take other as yet unknown steps to comply with these potential regulations. For example, we may have to purchase CO_2 emission reduction credits to reduce our current emissions of CO_2 or to offset increases in CO_2 emissions associated with expansions of our operations.

Compliance with any future legislation or regulation of greenhouse gas emissions, if it occurs, may have a material adverse effect on our results of operations, financial condition and profitability.

We are subject to strict laws and regulations regarding employee and process safety, and failure to comply with these laws and regulations could have a material adverse effect on our results of operations, financial condition and profitability.

We are subject to the requirements of the Occupational Safety and Health Administration, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, OSHA requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities, and local residents. Failure to comply with OSHA requirements, including general industry standards, process safety standards and control of occupational exposure to regulated substances, could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions if we are subjected to significant fines or compliance costs.

We have a limited operating history as a stand-alone company.

Our limited historical financial performance as a stand-alone company makes it difficult for you to evaluate our business and results of operations to date and to assess our future prospects and viability. We have been operating during a recent period of significant volatility in the refined products industry, and recent growth in the profitability of the nitrogen fertilizer products industry may not continue or could reverse. As a result, our results of operations may be lower than we currently expect and the price of our common stock may be volatile.

Because we have transferred our nitrogen fertilizer business to a newly formed limited partnership, we may be required in the future to share increasing portions of the cash flows of the nitrogen fertilizer business with third parties and we may in the future be required to deconsolidate the nitrogen fertilizer business from our consolidated financial statements.

In connection with our initial public offering in October 2007, we transferred our nitrogen fertilizer business to a newly formed limited partnership, whose managing general partner is a new entity owned by our controlling stockholders and senior management. Although we currently consolidate the Partnership in our financial statements, over time an increasing portion of the cash flow of the nitrogen fertilizer business will be distributed to our managing general partner if the Partnership increases its quarterly distributions above specified target distribution levels. In addition, if in the future the Partnership elects to pursue a public or private offering of limited partner interests to third parties, the new limited partners will also be entitled to receive cash distributions from the Partnership. This may require us to deconsolidate. Our historical financial statements do not reflect the new limited partnership structure prior to October 24, 2007 or any non-controlling interest that may be issued to the public in connection with a future initial offering of the Partnership and therefore our past financial performance may not be an accurate indicator of future performance.

Both the petroleum and nitrogen fertilizer businesses depend on significant customers, and the loss of one or several significant customers may have a material adverse impact on our results of operations and financial condition.

The petroleum and nitrogen fertilizer businesses both have a high concentration of customers. Our four largest customers in the petroleum business represented 44.4%, 36.8% and 40.2% of our petroleum sales for the years ended December 31, 2006 and 2007 and the three months ended March 31, 2008, respectively. Further, in the aggregate, the top five ammonia customers of the nitrogen fertilizer business represented 51.9%, 62.1% and 68.4% of its ammonia sales for the years ended December 31, 2006 and 2007 and the three months ended March 31, 2008, respectively, and the top five UAN customers of the nitrogen fertilizer business represented 30.0%, 38.7% and 42.4% of its UAN sales, respectively, for the same periods. Several significant petroleum, ammonia and UAN customers each account for more than 10% of sales of petroleum, ammonia and UAN, respectively. Given the nature of our business, and consistent with industry practice, we do not have long-term minimum purchase contracts with any of our customers. The loss of one or several of these significant customers, or a significant reduction in purchase volume by any of them, could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The petroleum and nitrogen fertilizer businesses may not be able to successfully implement their business strategies, which include completion of significant capital programs.

One of the business strategies of the petroleum and nitrogen fertilizer businesses is to implement a number of capital expenditure projects designed to increase productivity, efficiency and profitability. Many factors may prevent or hinder implementation of some or all of these projects, including compliance with or liability under environmental regulations, a downturn in refining margins, technical or mechanical problems, lack of availability of capital and other factors. Costs and delays have increased significantly during the past few years and the large number of capital projects underway in the industry has led to shortages in skilled craftsmen, engineering services and equipment manufacturing. Failure to successfully implement these profit-enhancing strategies may materially adversely affect our business prospects and competitive position. In addition, we expect to execute turnarounds at our refinery every three to four years, which involve numerous risks and uncertainties. These risks include delays and incurrence of additional and unforeseen costs. The next scheduled refinery turnaround will be in 2010. In addition, development and implementation of business strategies for the Partnership will be primarily the responsibility of the managing general partner of the Partnership. The next scheduled turnaround of the nitrogen fertilizer facility is currently expected to occur in the fourth quarter of 2008.

The acquisition strategy of our petroleum business and the nitrogen fertilizer business involves significant risks.

Both our petroleum business and the nitrogen fertilizer business will consider pursuing acquisitions and expansion projects in order to continue to grow and increase profitability. However, acquisitions and expansions involve numerous risks and uncertainties, including intense competition for suitable acquisition targets; the potential unavailability of financial resources necessary to consummate acquisitions and expansions; difficulties in identifying suitable acquisition targets and expansion projects or in completing any transactions identified on sufficiently favorable terms; and the need to obtain regulatory or other governmental approvals that may be necessary to complete acquisitions and expansions. In addition, any future acquisitions may entail significant transaction costs and risks associated with entry into new markets and lines of business. In addition, even when acquisitions are completed, integration of acquired entities can involve significant difficulties, such as:

- unforeseen difficulties in the acquired operations and disruption of the ongoing operations of our petroleum business and the nitrogen fertilizer business;
- failure to achieve cost savings or other financial or operating objectives with respect to an acquisition;
- strain on the operational and managerial controls and procedures of our petroleum business and the nitrogen fertilizer business, and the need to modify systems or to add management resources;
- difficulties in the integration and retention of customers or personnel and the integration and effective deployment of operations or technologies;
- assumption of unknown material liabilities or regulatory non-compliance issues;
- amortization of acquired assets, which would reduce future reported earnings;
- possible adverse short-term effects on our cash flows or operating results; and
- diversion of management s attention from the ongoing operations of our business.

Failure to manage these acquisition and expansion growth risks could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. There can be no assurance that we will be able to consummate any acquisitions or expansions, successfully integrate acquired entities, or generate positive cash flow at any acquired company or expansion project.

We are a holding company and depend upon our subsidiaries for our cash flow.

We are a holding company. Our subsidiaries conduct all of our operations and own substantially all of our assets. Consequently, our cash flow and our ability to meet our obligations or to pay dividends or make other distributions in the future will depend upon the cash flow of our subsidiaries and the payment of funds by our subsidiaries to us in the form of dividends, tax sharing payments or otherwise. In addition, Coffeyville Resources, LLC, our indirect subsidiary, which is the primary obligor under our existing credit facility, is a holding company and its ability to meet its debt service obligations depends on the cash flow of its subsidiaries. The ability of our subsidiaries to make any payments to us will depend on their earnings, the terms of their indebtedness, including the terms of our credit facility, tax considerations and legal restrictions. In particular, our credit facility currently imposes significant limitations on the ability of our subsidiaries to make distributions to us and consequently our ability to pay dividends to our stockholders. Distributions that we receive from the Partnership will be primarily reinvested in our business rather than distributed to our stockholders. See also Risks Related to the Nitrogen Fertilizer Business The nitrogen fertilizer business may not have sufficient cash to enable it to make quarterly distributions to us following the payment of expenses and fees and the establishment of cash reserves and Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest in the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time .

Our significant indebtedness may affect our ability to operate our business, and may have a material adverse effect on our financial condition and results of operations.

As of March 31, 2008, we had total debt outstanding of $488.0 million, $37.4 million in funded letters of credit outstanding and borrowing availability of $112.6 million under our credit facility. After giving effect to the concurrent convertible senior notes offering, we would have had total debt outstanding of $613.0 million ($631.8 million if the underwriters exercise their over allotment option), or $638.0 million ($656.8 million if the underwriters exercise their over allotment option) of total debt outstanding if the proposed senior secured credit facility (as defined under Description of Our Indebtedness Proposed Senior Secured Credit Facility) had also been entered into at that time. We and our subsidiaries may be able to incur significant additional indebtedness in the future. If new indebtedness is added to our current indebtedness, the risks described below could increase. Our high level of indebtedness could have important consequences, such as:

- making it more difficult to satisfy obligations to our creditors, including holders of the convertible senior notes;
- limiting our ability to obtain additional financing to fund our working capital, acquisitions, expenditures, debt service requirements or for other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service debt;
- limiting our ability to compete with other companies who are not as highly leveraged;
- placing restrictive financial and operating covenants in the agreements governing our and our subsidiaries long-term indebtedness and bank loans, including, in the case of certain indebtedness of subsidiaries, certain covenants that restrict the ability of subsidiaries to pay dividends or make other distributions to us;
- exposing us to potential events of default (if not cured or waived) under financial and operating covenants contained in our or our subsidiaries debt instruments that could have a material adverse effect on our business, financial condition and operating results;
- increasing our vulnerability to a downturn in general economic conditions or in pricing of our products; and
- limiting our ability to react to changing market conditions in our industry and in our customers industries.

In addition, borrowings under our existing credit facility (and the proposed senior secured credit facility, if we are successful in obtaining it) bear interest at variable rates. If market interest rates increase, such variable-rate debt will create higher debt service requirements, which could adversely affect our cash flow. Our interest expense for the year ended December 31, 2007 was $61.1 million. A 1% increase or decrease in the applicable interest rates under our credit facility, using average debt outstanding at March 31, 2008, would correspondingly change our interest expense by approximately

$4.9 million per year. If our credit ratings decline in the future, the interest rates we are charged on debt under our existing credit facility will increase by up to 0.75%.

In addition to our debt service obligations, our operations require substantial investments on a continuing basis. Our ability to make scheduled debt payments, including payments on the notes, to refinance our obligations with respect to our indebtedness and to fund capital and non-capital expenditures necessary to maintain the condition of our operating assets, properties and systems software, as well as to provide capacity for the growth of our business, depends on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and financial, business, competitive, legal and other factors. In addition, we are and will be subject to covenants contained in agreements governing our present and future indebtedness. These covenants include and will likely include restrictions on certain payments, the granting of liens, the incurrence of additional indebtedness, dividend restrictions affecting subsidiaries, asset sales, transactions with affiliates and mergers and consolidations. Any failure to comply with these covenants could result in a default under our credit facility and the indenture governing the notes. Upon a default, unless waived, the lenders under our credit facility would have all remedies available to a secured lender, and could elect to terminate their commitments, cease making further loans, institute foreclosure proceedings against our or our subsidiaries assets, and force us and our subsidiaries into bankruptcy or liquidation. In addition, any defaults under the credit facility, the indenture governing the notes or any other debt could trigger cross defaults under other or future credit agreements. Our operating results may not be sufficient to service our indebtedness or to fund our other expenditures and we may not be able to obtain financing to meet these requirements.

If the managing general partner of the Partnership elects to pursue a public or private offering of Partnership interests, we will be required to use our commercially reasonable efforts to amend our credit facility to remove the Partnership as a guarantor. Any such amendment could result in increased fees to us or other onerous terms in our credit facility. In addition, we may not be able to obtain such an amendment on terms acceptable to us or at all.

If the managing general partner of the Partnership elects to pursue a public or private offering of the Partnership, we will be required to obtain amendments to our credit facility, as well as to the Cash Flow Swap, in order to remove the Partnership and its subsidiaries as obligors under such instruments. Such amendments could be very expensive to obtain. Moreover, any such amendments could result in significant changes to our credit facility s pricing, mandatory repayment provisions, covenants and other terms and could result in increased interest costs and require payment by us of additional fees. We have agreed to use our commercially reasonable efforts to obtain such amendments if the managing general partner elects to cause the Partnership to pursue a public or private offering and gives us at least 90 days written notice. However, we may not be able to obtain any such amendment on terms acceptable to us or at all. If we are not able to amend our credit facility on terms satisfactory to us, we may need to refinance it with other facilities. We will not be considered to have used our commercially reasonable efforts to obtain such amendments if we do not effect the requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us.

If we lose any of our key personnel, we may be unable to effectively manage our business or continue our growth.

Our future performance depends to a significant degree upon the continued contributions of our senior management team and key technical personnel. The loss or unavailability to us of any member of our senior management team or a key technical employee could negatively affect our ability to operate our business and pursue our strategy. We face competition for these professionals from our competitors, our customers and other companies operating in our industry. To the extent that the

Table of Contents

services of members of our senior management team and key technical personnel would be unavailable to us for any reason, we would be required to hire other personnel to manage and operate our company and to develop our products and strategy. We may not be able to locate or employ such qualified personnel on acceptable terms or at all.

A substantial portion of our workforce is unionized and we are subject to the risk of labor disputes and adverse employee relations, which may disrupt our business and increase our costs.

As of March 31, 2008, approximately 42% of our employees, all of whom work in our petroleum business, were represented by labor unions under collective bargaining agreements expiring in 2009. We may not be able to renegotiate our collective bargaining agreements when they expire on satisfactory terms or at all. A failure to do so may increase our costs. In addition, our existing labor agreements may not prevent a strike or work stoppage at any of our facilities in the future, and any work stoppage could negatively affect our results of operations and financial condition.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

We are subject to the reporting requirements of the Securities Exchange Act of 1934 (the Exchange Act) and the corporate governance standards of the Sarbanes-Oxley Act of 2002 (the Sarbanes-Oxley Act). These requirements may place a strain on our management, systems and resources. The Exchange Act requires that we file annual, quarterly and current reports with respect to our business and financial condition. The Sarbanes-Oxley Act requires that we maintain effective disclosure controls and procedures and internal control over financial reporting. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight will be required. This may divert management s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and the price of our common stock.

In April 2008, we concluded that our consolidated financial statements for the year ended December 31, 2007 and the related quarter ended September 30, 2007 contained errors principally related to the calculation of the cost of crude oil purchased by us and associated financial transactions. As a result of these errors, management concluded that our internal controls were not adequate to determine the cost of crude oil at September 30, 2007 and December 31, 2007. Specifically, the Company s policies and procedures for estimating the cost of crude oil and reconciling these estimates to vendor invoices were not effective. Additionally, the Company s supervision and review of this estimation and reconciliation process was not operating at a level of detail adequate to identify the deficiencies in the process. Management concluded that these deficiencies were material weaknesses in our internal control over financial reporting. Due to these material weaknesses, our management also concluded that we did not maintain effective disclosure controls and procedures as of December 31, 2007.

In order to remediate the material weaknesses described above, our management is in the process of designing, implementing and enhancing controls to ensure the proper accounting for the calculation of the cost of crude oil. These remedial actions include, among other things, (1) centralizing all crude oil cost accounting functions, (2) adding additional layers of accounting review with respect to our crude oil cost accounting and (3) adding additional layers of business review with respect to the computation of our crude oil costs.

Table of Contents

We will be exposed to risks relating to evaluations of controls required by Section 404 of the Sarbanes-Oxley Act.

We are in the process of evaluating our internal control systems to allow management to report on, and our independent auditors to audit, our internal control over financial reporting. We will be performing the system and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, and will be required to comply with Section 404 in our annual report for the year ended December 31, 2008 (subject to any change in applicable SEC rules). Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable SEC and Public Company Accounting Oversight Board (PCAOB) rules and regulations that remain unremediated. Although we produce our financial statements in accordance with GAAP, our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. We will be required to report, among other things, control deficiencies that constitute a material weakness or changes in internal controls that, or that are reasonably likely to, materially affect internal control over financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC or the PCAOB. If we do not implement improvements to our disclosure controls and procedures or to our internal control over financial reporting in a timely manner, our independent registered public accounting firm may not be able to certify as to the effectiveness of our internal control over financial reporting pursuant to an audit of our internal control over financial reporting. This may subject us to adverse regulatory consequences or a loss of confidence in the reliability of our financial statements. We could also suffer a loss of confidence in the reliability of our financial statements if our independent registered public accounting firm reports a material weakness in our internal controls, if we do not develop and maintain effective controls and procedures or if we are otherwise unable to deliver timely and reliable financial information. Any loss of confidence in the reliability of our financial statements or other negative reaction to our failure to develop timely or adequate disclosure controls and procedures or internal control over financial reporting could result in a decline in the price of our common stock. In addition, if we fail to remedy any material weakness, our financial statements may be inaccurate, we may face restricted access to the capital markets and the price of our common stock may be adversely affected.

We are a controlled company within the meaning of the New York Stock Exchange rules and, as a result, qualify for, and are relying on, exemptions from certain corporate governance requirements.

A company of which more than 50% of the voting power is held by an individual, a group or another company is a controlled company within the meaning of the New York Stock Exchange rules and may elect not to comply with certain corporate governance requirements of the New York Stock Exchange, including:

- the requirement that a majority of our board of directors consist of independent directors;

- the requirement that we have a nominating/corporate governance committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities; and

- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities.

We are relying on all of these exemptions as a controlled company. Accordingly, our stockholders do not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the New York Stock Exchange.

New regulations concerning the transportation of hazardous chemicals, risks of terrorism and the security of chemical manufacturing facilities could result in higher operating costs.

The costs of complying with regulations relating to the transportation of hazardous chemicals and security associated with the refining and nitrogen fertilizer facilities may have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. Targets such as refining and chemical manufacturing facilities may be at greater risk of future terrorist attacks than other targets in the United States. As a result, the petroleum and chemical industries have responded to the issues that arose due to the terrorist attacks on September 11, 2001 by starting new initiatives relating to the security of petroleum and chemical industry facilities and the transportation of hazardous chemicals in the United States. Future terrorist attacks could lead to even stronger, more costly initiatives. Simultaneously, local, state and federal governments have begun a regulatory process that could lead to new regulations impacting the security of refinery and chemical plant locations and the transportation of petroleum and hazardous chemicals. Our business or our customers businesses could be materially adversely affected by the cost of complying with new regulations.

We may face third-party claims of intellectual property infringement, which if successful could result in significant costs for our business.

There are currently no claims pending against us relating to the infringement of any third-party intellectual property rights. However, in the future we may face claims of infringement that could interfere with our ability to use technology that is material to our business operations. Any litigation of this type, whether successful or unsuccessful, could result in substantial costs to us and diversions of our resources, either of which could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. In the event a claim of infringement against us is successful, we may be required to pay royalties or license fees for past or continued use of the infringing technology, or we may be prohibited from using the infringing technology altogether. If we are prohibited from using any technology as a result of such a claim, we may not be able to obtain licenses to alternative technology adequate to substitute for the technology we can no longer use, or licenses for such alternative technology may only be available on terms that are not commercially reasonable or acceptable to us. In addition, any substitution of new technology for currently licensed technology may require us to make substantial changes to our manufacturing processes or equipment or to our products and could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

If licensed technology is no longer available, the refinery and nitrogen fertilizer businesses may be adversely affected.

We have licensed, and may in the future license, a combination of patent, trade secret and other intellectual property rights of third parties for use in our business. If any of these license agreements were to be terminated, licenses to alternative technology may not be available, or may only be available on terms that are not commercially reasonable or acceptable. In addition, any substitution of new technology for currently licensed technology may require substantial changes to manufacturing processes or equipment and may have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

45

Risks Related to Our Common Stock

If our stock price fluctuates, investors could lose a significant part of their investment.

The market price of our common stock may be influenced by many factors including:

- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- announcements by us or our competitors of significant contracts or acquisitions;
- variations in quarterly results of operations;
- loss of a large customer or supplier;
- general economic conditions;
- terrorist acts;
- future sales of our common stock; and
- investor perceptions of us and the industries in which our products are used.

As a result of these factors, investors in our common stock may not be able to resell their shares at or above the price at which they purchase our common stock. In addition, the stock market in general has experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of companies like us. These broad market and industry factors may materially reduce the market price of our common stock, regardless of our operating performance.

Following the completion of this offering, the Goldman Sachs Funds and the Kelso Funds will continue to control us and may have conflicts of interest with other stockholders. Conflicts of interest may arise because our principal stockholders or their affiliates have continuing agreements and business relationships with us.

Upon completion of this offering, the Goldman Sachs Funds will control 30.7% of our outstanding common stock, or 29.8% if the underwriters exercise their option in full, and the Kelso Funds will control 30.7% of our outstanding common stock, or 29.8% if the underwriters exercise their option in full. Due to their equity ownership, the Goldman Sachs Funds and the Kelso Funds are able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other stockholders, the outcome of any corporate transaction or other matter submitted to our stockholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. The Goldman Sachs Funds and the Kelso Funds also have sufficient voting power to amend our organizational documents.

Conflicts of interest may arise between our principal stockholders and us. Affiliates of some of our principal stockholders engage in transactions with our company. We obtain the majority of our crude oil supply through a crude oil credit intermediation agreement with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and an affiliate of the Goldman Sachs Funds, and Coffeyville Resources, LLC currently has entered into commodity derivative contracts (swap agreements) with J. Aron for the period from July 1, 2005 to June 30, 2010. In addition, Goldman Sachs Credit Partners, L.P. is the joint lead arranger for our credit facility. See Certain Relationships and Related Party Transactions. Further, the Goldman Sachs Funds and the Kelso Funds are in the business of making investments in companies and may, from time to time, acquire and hold interests in businesses that compete directly or indirectly with us and they may either directly, or through affiliates, also maintain business relationships with companies that may directly compete with us. In general, the Goldman Sachs Funds and the Kelso Funds or their affiliates could pursue business interests or exercise their voting power as stockholders in ways that are detrimental to us, but beneficial to themselves or to other companies in which they invest or with whom they have a material relationship. Conflicts of interest could also arise with respect to business opportunities that could be advantageous to the Goldman Sachs Funds and the Kelso Funds and they may pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us. Under the terms of our certificate of incorporation, the Goldman Sachs Funds and the Kelso Funds have no obligation to offer us corporate opportunities. See Description of Capital Stock Corporate Opportunities .

Other conflicts of interest may arise between our principal stockholders and us because the Goldman Sachs Funds and the Kelso Funds control the managing general partner of the Partnership which holds the nitrogen fertilizer business. The managing general partner manages the operations of the Partnership (subject to our rights to participate in the appointment, termination and compensation of the chief executive officer and chief financial officer of the managing general partner and our other specified joint management rights) and also holds IDRs which, over time, entitle the managing general partner to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases the amount of distributions. Although the managing general partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and us (as a holder of special units in the Partnership), the fiduciary duty is limited by the terms of the partnership agreement and the directors and officers of the managing general partner also have a fiduciary duty to manage the managing general partner in a manner beneficial to the owners of the managing general partner. The interests of the owners of the managing general partner may differ significantly from, or conflict with, our interests and the interests of our stockholders.

Under the terms of the Partnership s partnership agreement, the Goldman Sachs Funds and the Kelso Funds have no obligation to offer the Partnership business opportunities. The Goldman Sachs Funds and the Kelso Funds may pursue acquisition opportunities for themselves that would be otherwise beneficial to the nitrogen fertilizer business and, as a result, these acquisition opportunities would not be available to the Partnership. The partnership agreement provides that the owners of its managing general partner, which include the Goldman Sachs Funds and the Kelso Funds, are permitted to engage in separate businesses that directly compete with the nitrogen fertilizer business and are not required to share or communicate or offer any potential business opportunities to the Partnership even if the opportunity is one that the Partnership might reasonably have pursued. The agreement provides that the owners of our managing general partner will not be liable to the Partnership or any unitholder for breach of any fiduciary or other duty by reason of the fact that such person pursued or acquired for itself any business opportunity.

As a result of these conflicts, the managing general partner of the Partnership may favor its own interests and/or the interests of its owners over our interests and the interests of our stockholders (and the interests of the Partnership). In particular, because the managing general partner owns the IDRs, it may be incentivized to maximize future cash flows by taking current actions which may be in its best interests over the long term. See Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest in the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest in the Nitrogen Fertilizer Business The managing general partner of the Partnership has a fiduciary duty to favor the interests of its owners, and these interests may differ from, or conflict with, our interests and the interests of our stockholders . In addition, if the value of the managing general partner interest were to increase over time, this increase in value and any realization of such value upon a sale of the managing general partner interest would benefit the owners of the managing general partner, which are the Goldman Sachs Funds, the Kelso Funds and our senior management, rather than our company and our stockholders. Such increase in value could be significant if the Partnership performs well. See The Nitrogen Fertilizer Limited Partnership .

Further, decisions made by the Goldman Sachs Funds and the Kelso Funds with respect to their shares of common stock could trigger cash payments to be made by us to certain members of our senior management under the Phantom Unit Plans. Phantom points granted under the Coffeyville

Resources, LLC Phantom Unit Appreciation Plan (Plan I), or the Phantom Unit Plan I, and phantom points that we granted under the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II), or the Phantom Unit Plan II, represent a contractual right to receive a cash payment when payment is made in respect of certain profits interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Definitions of the terms phantom points, Phantom Unit Plan I and Phantom Unit Plan II are contained in the section of this prospectus entitled Glossary of Selected Terms . If either the Goldman Sachs Funds or the Kelso Funds sell any of the shares of common stock of CVR Energy which they beneficially own through Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, they may then cause Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, to make distributions to their members in respect of their profits interests. Because payments under the Phantom Unit Plans are triggered by payments in respect of profit interests under the Coffeyville Acquisition LLC Agreement and Coffeyville Acquisition II LLC Agreement, we would therefore be obligated to make cash payments under the Phantom Unit Plans. This could negatively affect our cash reserves, which could have a material adverse effect our results of operations, financial condition and cash flows. We estimate that any such cash payments should not exceed $65 million, assuming all of the shares of our common stock held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at $24.92 per share, which was the closing price of our common stock on June 16, 2008.

Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC have informed us that they intend to make distributions to their members with the proceeds of this offering. Accordingly, we estimate that in connection with this offering we will be required to make cash payments pursuant to the Phantom Unit Plans in an amount of approximately $3.5 million ($4.3 million if underwriters exercise their option to purchase additional shares in full), assuming the shares of common stock are sold at $24.92 per share, which was the closing price of our common stock on June 16, 2008.

In addition, one of the Goldman Sachs Funds and one of the Kelso Funds have each guaranteed 50% of our payment obligations under the Cash Flow Swap in the amount of $123.7 million, plus accrued interest ($5.8 million as of June 1, 2008). These payments under the Cash Flow Swap are due in August 2008. As a result of these guarantees, the Goldman Sachs Funds and the Kelso Funds may have interests that conflict with those of our other shareholders.

Since June 24, 2005, we have made two cash distributions to the Goldman Sachs Funds and the Kelso Funds. One distribution, in the aggregate amount of $244.7 million, was made in December 2006. In addition, in October 2007, we made a special dividend to the Goldman Sachs Funds and the Kelso Funds in an aggregate amount of approximately $10.3 million, which they contributed to Coffeyville Acquisition III LLC in connection with the purchase of the managing general partner of the Partnership from us.

As a result of these relationships, including their ownership of the managing general partner of the Partnership, the interests of the Goldman Sachs Funds and the Kelso Funds may not coincide with the interests of our company or other holders of our common stock. So long as the Goldman Sachs Funds and the Kelso Funds continue to control a significant amount of the outstanding shares of our common stock, the Goldman Sachs Funds and the Kelso Funds will continue to be able to strongly influence or effectively control our decisions, including potential mergers or acquisitions, asset sales and other significant corporate transactions. In addition, so long as the Goldman Sachs Funds and the Kelso Funds continue to control the managing general partner of the Partnership, they will be able to effectively control actions taken by the Partnership (subject to our specified joint management rights), which may not be in our interests or the interest of our stockholders. See Certain Relationships and Related Party Transactions .

Table of Contents

Shares eligible for future sale, and the convertible notes we may issue concurrently with this offering, may cause the price of our common stock to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. This could also impair our ability to raise additional capital through the sale of our equity securities. Under our amended and restated certificate of incorporation, we are authorized to issue up to 350,000,000 shares of common stock, of which 86,141,291 shares of common stock were outstanding as of the date of this prospectus. Of these shares, the 23,000,000 shares of common stock sold in our initial public offering, the 27,100 shares of common stock granted to our non-executive officer employees in connection with our initial public offering and registered pursuant to a Registration Statement on Form S-8 filed with the SEC on October 24, 2007 and the shares of common stock sold in this offering, will be freely transferable without restriction or further registration under the Securities Act by persons other than affiliates, as that term is defined in Rule 144 under the Securities Act.

Further, shares of our common stock are reserved for issuance on the exercise of stock options and on conversion of our convertible notes, assuming the convertible senior notes offering is consummated. To the extent we issue any shares of our common stock upon conversion of the convertible notes, the conversion or some or all of the convertible notes will dilute the ownership interests of existing stockholders, including those who purchase shares of common stock in this offering. In addition, the existence of the convertible notes may encourage short selling by market participants because the conversion of the notes could depress the price of our common stock. Holders of debt securities sold by CVR Energy, including the convertible notes that we may offer concurrently with this offering, will be preferred in right of payment to holders of our common stock.

Following this offering, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will own collectively 52,911,720 shares of our common stock. Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC each have demand and piggyback registration rights with respect to these shares. In connection with this offering, the selling stockholders and our directors and officers will enter into lock up agreements, pursuant to which they are expected to agree, subject to certain exceptions, not to sell or transfer, directly or indirectly, any additional shares of our common stock for a period of 90 days from the date of this prospectus, subject to extension in certain circumstances. See Shares Eligible for Future Sale .

Convertible notes that we may offer concurrently with this offering may cause the price of our common stock to decline.

The price of our common stock could also be affected by possible sales of our common stock by investors who view the convertible notes as a more attractive means of equity participation in CVR Energy and by hedging or arbitrage activity that we expect to develop involving our common stock. The hedging or arbitrage could, in turn, affect the trading price of our common stock.

The accounting for the convertible notes we may issue concurrently with this offering will result in our having to recognize interest expense significantly more than the stated interest rate of the convertible notes in our financial statements after the start of our fiscal year beginning on January 1, 2009. This accounting change could have a negative effect on the price of our common stock.

The convertible notes will have a net share settlement feature. Under the current accounting rules, for the purpose of calculating diluted earnings per share, a net share settled convertible security meeting certain requirements is accounted for in a manner similar to nonconvertible debt, with the stated coupon constituting interest expense and any shares issuable upon conversion of the security being accounted for in a manner similar to the treasury stock method. The effect of this method is that the shares potentially issuable upon conversion of the securities are not included in the calculation of

earnings per share until the conversion price is in the money, and the issuer is then assumed to issue the number of shares necessary to settle the conversion.

However, the Financial Accounting Standards Board (FASB) recently posted FASB Staff Position (FSP) No. APB 14-1 Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlements) (previously FSP APB 14-a), which will change the accounting treatment for net share settled convertible securities. Under the final FSP, cash settled convertible securities will be separated into their debt and equity components. The value assigned to the debt component will be the estimated fair value, as of the issuance date, of a similar debt instrument without the conversion feature, and the difference between the proceeds for the convertible debt and the amount reflected as a debt liability will be recorded as additional paid-in capital. As a result, the debt will be recorded at a discount reflecting its below market coupon interest rate. The debt will subsequently be accreted to its par value over its expected life, with the rate of interest that reflects the market rate at issuance being reflected on the income statement. This change in methodology will affect the calculations of net income and earnings per share for many issuers of cash settled convertible securities.

Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest in the Nitrogen Fertilizer Business

Because we neither serve as, nor control, the managing general partner of the Partnership, the managing general partner may operate the Partnership in a manner with which we disagree or which is not in our interest.

CVR GP, LLC or Fertilizer GP, which is owned by our controlling stockholders and senior management, is the managing general partner of the Partnership which holds the nitrogen fertilizer business. The managing general partner is authorized to manage the operations of the nitrogen fertilizer business (subject to our specified joint management rights), and we do not control the managing general partner. Although our senior management also serves as the senior management of Fertilizer GP, in accordance with a services agreement among us, Fertilizer GP and the Partnership, our senior management operates the Partnership under the direction of the managing general partner s board of directors and Fertilizer GP has the right to select different management at any time (subject to our joint right in relation to the chief executive officer and chief financial officer of the managing general partner). Accordingly, the managing general partner may operate the Partnership in a manner with which we disagree or which is not in the interests of our company and our stockholders.

Our interest in the Partnership currently gives us defined rights to participate in the management and governance of the Partnership. These rights include the right to approve the appointment, termination of employment and compensation of the chief executive officer and chief financial officer of Fertilizer GP, not to be exercised unreasonably, and to approve specified major business transactions such as significant mergers and asset sales. We also have the right to appoint two directors to Fertilizer GP s board of directors. However, we will lose the rights listed above if we fail to hold at least 15% of the units in the Partnership.

The amount of cash the nitrogen fertilizer business has available for distribution to us depends primarily on its cash flow and not solely on its profitability. If the nitrogen fertilizer business has insufficient cash to cover intended distribution payments, it would need to reduce or eliminate distributions to us or, to the extent permitted under agreements governing indebtedness that the nitrogen fertilizer business may incur in the future, fund a portion of its distributions with borrowings.

The amount of cash the nitrogen fertilizer business has available for distribution depends primarily on its cash flow, including working capital borrowings, and not solely on profitability, which

will be affected by non-cash items. As a result, the nitrogen fertilizer business may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records net income.

If the nitrogen fertilizer business does not have sufficient cash to cover intended distribution payments, it would either reduce or eliminate distributions or, to the extent permitted to do so under any revolving line of credit or other debt facility that the nitrogen fertilizer business may enter into in the future, fund a portion of its distributions with borrowings. If the nitrogen fertilizer business were to use borrowings under a revolving line of credit or other debt facility to fund distributions, its indebtedness levels would increase and its ongoing debt service requirements would increase and therefore it would have less cash available for future distributions and other purposes, including the funding of its ongoing expenses. This could negatively impact the nitrogen fertilizer business financial condition, results of operations, ability to pursue its business strategy and ability to make future distributions. We cannot assure you that borrowings would be available to the nitrogen fertilizer business under a revolving line of credit or other debt facility to fund distributions.

The Partnership may elect not to or may be unable to consummate an initial public offering or one or more private placements. This could negatively impact the value and liquidity of our investment in the Partnership, which could impact the value of our common stock.

The Partnership may elect not to or may be unable to consummate an initial public offering or an initial private offering. Any public or private offering of interests by the Partnership will be made at the discretion of the managing general partner of the Partnership and will be subject to market conditions and to achievement of a valuation which the Partnership finds acceptable. Although the Partnership filed a registration statement with the SEC in February 2008, the Partnership subsequently requested that the registration statement be withdrawn, and there can be no assurance that the Partnership will file a new registration statement with the SEC in the future. An initial public offering is subject to SEC review of a registration statement, compliance with applicable securities laws and the Partnership s ability to list Partnership units on a national securities exchange. Similarly, any private placement to a third party would depend on the Partnership s ability to reach agreement on price and enter into satisfactory documentation with a third party. Any such transaction would also require third party approvals, including consent of our lenders under our credit facility and the swap counterparty under our Cash Flow Swap, which would be very expensive. The Partnership may never consummate any of such transactions on terms favorable to us, or at all. If no offering by the Partnership is ever made, it could impact the value, and certainly the liquidity, of our investment in the Partnership.

If the Partnership does not consummate an initial public offering, the value of our investment in the Partnership could be negatively impacted because the Partnership would not be able to access public equity markets to fund capital projects and would not have a liquid currency with which to make acquisitions or consummate other potentially beneficial transactions. In addition, we would not have a liquid market in which to sell portions of our interest in the Partnership but rather would need to monetize our interest in a privately negotiated sale if we ever wished to create liquidity through a divestiture of our nitrogen fertilizer business. In addition, if the Partnership does not consummate an initial public offering by October 24, 2009, Fertilizer GP can require us to purchase its managing general partner in the Partnership. See If the Partnership does not consummate an initial offering by October 24, 2009, Fertilizer GP can require us to purchase its managing general partner interest in the Partnership. We may not have requisite funds to do so.

We have agreed with the Partnership that we will not own or operate any fertilizer business in the United States or abroad (with limited exceptions).

We have entered into an omnibus agreement with the Partnership in order to clarify and structure the division of corporate opportunities between the Partnership and us. Under this agreement, we have agreed not to engage in the production, transportation or distribution, on a wholesale basis, of fertilizers in the contiguous United States, subject to limited exceptions (fertilizer restricted business). The Partnership has agreed not to engage in the ownership or operation within the United States of any refinery with processing capacity greater than 20,000 bpd whose primary business is producing transportation fuels or the ownership or operation outside the United States of any refinery, regardless of its processing capacity or primary business (refinery restricted business).

With respect to any business opportunity other than those covered by a fertilizer restricted business or a refinery restricted business, we and the Partnership have agreed that the Partnership will have a preferential right to pursue such opportunities before we may pursue them. If the Partnership s managing general partner elects not to cause the Partnership to pursue the business opportunity, then we will be free to pursue such opportunity. This provision and the non-competition provisions described in the previous paragraph will continue so long as we and certain of our affiliates continue to own 50% or more of the outstanding units of the Partnership.

Our rights to receive distributions from the Partnership may be limited over time.

As a holder of 30,333,333 special units (which may convert into general partner and/or subordinated general partner units if the Partnership consummates an initial public or private offering, and which we may sell from time to time), we are entitled to receive a quarterly distribution of $0.4313 per unit (or $13.1 million per quarter in the aggregate, assuming we do not sell any of our units) from the Partnership to the extent the Partnership has sufficient available cash after establishment of cash reserves and payment of fees and expenses before any distributions are made in respect of the IDRs. The Partnership is required to distribute all of its cash on hand at the end of each quarter, less reserves established by the managing general partner in its discretion. In addition, the managing general partner, Fertilizer GP, will have no right to receive distributions in respect of its IDRs (i) until the Partnership has distributed all aggregate adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009 and (ii) for so long as the Partnership or its subsidiaries are guarantors under our credit facility.

However, distributions of amounts greater than the aggregate adjusted operating surplus (as defined under The Nitrogen Fertilizer Limited Partnership Cash Distributions by the Partnership Definition of Adjusted Operating Surplus) generated through December 31, 2009 will be allocated between us and Fertilizer GP (and the holders of any other interests in the Partnership), and in the future the allocation will grant Fertilizer GP a greater percentage of the Partnership s cash distributions as more cash becomes available for distribution. After the Partnership has distributed all adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009, if quarterly distributions exceed the target of $0.4313 per unit, Fertilizer GP will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level, in respect of its IDRs. Therefore, we will receive a smaller percentage of quarterly cash distributions from the Partnership if the Partnership increases its quarterly distributions above the target distribution levels. Because Fertilizer GP does not share in adjusted operating surplus generated prior to December 31, 2009, Fertilizer GP could be incentivized to cause the Partnership to make capital expenditures for maintenance prior to such date, which would reduce operating surplus, rather than for expansion, which would not, and, accordingly, affect the amount of operating surplus generated. Fertilizer GP could also be incentivized to cause the Partnership to make capital expenditures for maintenance prior to December 31, 2009 that it would otherwise make at a later date in order to reduce operating surplus generated prior to such date. In addition, Fertilizer GP s discretion in determining the level of cash reserves may materially adversely affect the Partnership s ability to make cash distributions to us.

Moreover, if the Partnership issues common units in a public or private offering, at least 40% (and potentially all) of our special units will become subordinated units. We will not be entitled to any distributions on our subordinated units until the common units issued in the public or private offering and our GP units have received the minimum quarterly distribution (MQD) of $0.375 per unit (which may be reduced without our consent in connection with the public or private offering, or could be increased with our consent), plus any accrued and unpaid arrearages in the minimum quarterly

Table of Contents

distribution from prior quarters. The managing general partner, and not CVR Energy, has authority to decide whether or not to pursue such an offering. As a result, our right to distributions will diminish if the managing general partner decides to pursue such an offering.

The managing general partner of the Partnership has a fiduciary duty to favor the interests of its owners, and these interests may differ from, or conflict with, our interests and the interests of our stockholders.

The managing general partner of the Partnership, Fertilizer GP, is responsible for the management of the Partnership (subject to our specified management rights). Although Fertilizer GP has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and holders of interests in the Partnership (including us, in our capacity as holder of special units), the fiduciary duty is specifically limited by the express terms of the partnership agreement and the directors and officers of Fertilizer GP also have a fiduciary duty to manage Fertilizer GP in a manner beneficial to the owners of Fertilizer GP. The interests of the owners of Fertilizer GP may differ from, or conflict with, our interests and the interests of our stockholders. In resolving these conflicts, Fertilizer GP may favor its own interests and/or the interests of its owners over our interests and the interests of our stockholders (and the interests of the Partnership). In addition, while our directors and officers have a fiduciary duty to make decisions in our interests and the interests of our stockholders, one of our wholly-owned subsidiaries is also a general partner of the Partnership and, therefore, in such capacity, has a fiduciary duty to exercise rights as general partner in a manner beneficial to the Partnership and its unitholders, subject to the limitations contained in the partnership agreement. As a result of these conflicts, our directors and officers may feel obligated to take actions that benefit the Partnership as opposed to us and our stockholders.

The potential conflicts of interest include, among others, the following:

Fertilizer GP, as managing general partner of the Partnership, holds all of the IDRs in the Partnership. IDRs give Fertilizer GP a right to increasing percentages of the Partnership s quarterly distributions after the Partnership has distributed all adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009, assuming the Partnership and its subsidiaries are released from their guaranty of our credit facility and if the quarterly distributions exceed the target of $0.4313 per unit. Fertilizer GP may have an incentive to manage the Partnership in a manner which preserves or increases the possibility of these future cash flows rather than in a manner that preserves or increases current cash flows.

Fertilizer GP may also have an incentive to engage in conduct with a high degree of risk in order to increase cash flows substantially and thereby increase the value of the IDRs instead of following a safer course of action.

The owners of Fertilizer GP, who are also our controlling stockholders and senior management, are permitted to compete with us or the Partnership or to own businesses that compete with us or the Partnership. In addition, the owners of Fertilizer GP are not required to share business opportunities with us, and our owners are not required to share business opportunities with the Partnership or Fertilizer GP.

Neither the partnership agreement nor any other agreement requires the owners of Fertilizer GP to pursue a business strategy that favors us or the Partnership. The owners of Fertilizer GP have fiduciary duties to make decisions in their own best interests, which may be contrary to our interests and the interests of the Partnership. In addition, Fertilizer GP is allowed to take into account the interests of parties other than us, such as its owners, or the Partnership in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us.

Fertilizer GP has limited its liability and reduced its fiduciary duties under the partnership agreement and has also restricted the remedies available to the unitholders of the Partnership, including us, for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of our ownership interest in the Partnership, we may consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.

Fertilizer GP determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, repayment of indebtedness, issuances of additional partnership interests and cash reserves maintained by the Partnership (subject to our specified joint management rights), each of which can affect the amount of cash that is available for distribution to us in our capacity as a holder of special units and the amount of cash paid to Fertilizer GP in respect of its IDRs.

Fertilizer GP will also able to determine the amount and timing of any capital expenditures and whether a capital expenditure is for maintenance, which reduces operating surplus, or expansion, which does not. Such determinations can affect the amount of cash that is available for distribution and the manner in which the cash is distributed.

In some instances Fertilizer GP may cause the Partnership to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions, which may not be in our interests.

The partnership agreement permits the Partnership to classify up to $60 million as operating surplus, even if this cash is generated from asset sales, borrowings other than working capital borrowings or other sources the distribution of which would otherwise constitute capital surplus. This cash may be used to fund distributions in respect of the IDRs.

The partnership agreement does not restrict Fertilizer GP from causing the nitrogen fertilizer business to pay it or its affiliates for any services rendered to the Partnership or entering into additional contractual arrangements with any of these entities on behalf of the Partnership.

Fertilizer GP may exercise its rights to call and purchase all of the Partnership s equity securities of any class if at any time it and its affiliates (excluding us) own more than 80% of the outstanding securities of such class.

Fertilizer GP controls the enforcement of obligations owed to the Partnership by it and its affiliates. In addition, Fertilizer GP decides whether to retain separate counsel or others to perform services for the Partnership.

Fertilizer GP determines which costs incurred by it and its affiliates are reimbursable by the Partnership.

The executive officers of Fertilizer GP, and the majority of the directors of Fertilizer GP, also serve as our directors and/or executive officers. The executive officers who work for both us and Fertilizer GP, including our chief executive officer, chief operating officer, chief financial officer and general counsel, divide their time between our business and the business of the Partnership. These executive officers will face conflicts of interest from time to time in making decisions which may benefit either us or the Partnership.

The partnership agreement limits the fiduciary duties of the managing general partner and restricts the remedies available to us for actions taken by the managing general partner that might otherwise constitute breaches of fiduciary duty.

The partnership agreement contains provisions that reduce the standards to which Fertilizer GP, as the managing general partner, would otherwise be held by state fiduciary duty law. For example:

The partnership agreement permits Fertilizer GP to make a number of decisions in its individual capacity, as opposed to its capacity as managing general partner. This entitles Fertilizer GP to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us or our affiliates. Decisions made by Fertilizer GP in its individual capacity will be made by the sole member of Fertilizer GP, and not by the board of directors of Fertilizer GP. Examples include the exercise of its limited call right, its voting rights, its registration rights and its determination whether or not to consent to any merger or consolidation or amendment to the partnership agreement.

The partnership agreement provides that Fertilizer GP will not have any liability to the Partnership or to us for decisions made in its capacity as managing general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the Partnership.

The partnership agreement provides that Fertilizer GP and its officers and directors will not be liable for monetary damages to the Partnership for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that Fertilizer GP or those persons acted in bad faith or engaged in fraud or willful misconduct, or in the case of a criminal matter, acted with knowledge that such person s conduct was criminal.

The partnership agreement generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of Fertilizer GP and not involving a vote of unitholders must be on terms no less favorable to the Partnership than those generally provided to or available from unrelated third parties or be fair and reasonable. In determining whether a transaction or resolution is fair and reasonable, Fertilizer GP may consider the totality of the relationship between the parties involved, including other transactions that may be particularly advantageous or beneficial to the Partnership.

The Partnership has a preferential right to pursue corporate opportunities before we can pursue them.

We have entered into an agreement with the Partnership in order to clarify and structure the division of corporate opportunities between us and the Partnership. Under this agreement, we have agreed not to engage in the production, transportation or distribution, on a wholesale basis, of fertilizers in the contiguous United States, subject to limited exceptions (fertilizer restricted business). In addition, the Partnership has agreed not to engage in the ownership or operation within the United States of any refinery with processing capacity greater than 20,000 barrels per day whose primary business is producing transportation fuels or the ownership or operation outside the United States of any refinery (refinery restricted business).

With respect to any business opportunity other than those covered by a fertilizer restricted business or a refinery restricted business, we have agreed that the Partnership will have a preferential right to pursue such opportunities before we may pursue them. If the managing general partner of the Partnership elects not to pursue the business opportunity, then we will be free to pursue such opportunity. This provision will continue so long as we continue to own 50% of the outstanding units of the Partnership. See The Nitrogen Fertilizer Limited Partnership Intercompany Agreements Omnibus Agreement.

If the Partnership elects to pursue and completes a public offering or private placement of limited partner interests, our voting power in the Partnership would be reduced and our rights to distributions from the Partnership could be materially adversely affected.

Fertilizer GP may, in its sole discretion, elect to pursue one or more public or private offerings of limited partner interests in the Partnership. Fertilizer GP will have the sole authority to determine the timing, size (subject to our joint management rights for any initial offering in excess of $200 million, exclusive of the underwriters option to purchase additional limited partner interests, if any), and underwriters or initial purchasers, if any, for such offerings, if any. Any public or private offering of

limited partner interests could materially adversely affect us in several ways. For example, if such an offering occurs, our percentage interest in the Partnership would be diluted. Some of our voting rights in the Partnership could thus become less valuable, since we would not be able to take specified actions without support of other unitholders. For example, since the vote of 80% of unitholders is required to remove the managing general partner in specified circumstances, if the managing general partner sells more than 20% of the units to a third party we would not have the right, unilaterally, to remove the general partner under the specified circumstances.

In addition, if the Partnership completes an offering of limited partner interests, the distributions that we receive from the Partnership would decrease because the Partnership s distributions will have to be shared with the new limited partners, and the new limited partners right to distributions will be superior to ours because at least 40% (and potentially all) of our units will become subordinated units. Pursuant to the terms of the partnership agreement, the new limited partners and Fertilizer GP will have superior priority to distributions in some circumstances. Subordinated units will not be entitled to receive distributions unless and until all common units and any other units senior to the subordinated units have received the minimum quarterly distribution, plus any accrued and unpaid arrearages in the MQD from prior quarters. In addition, upon a liquidation of the Partnership, common unitholders will have a preference over subordinated unitholders in certain circumstances.

If the Partnership does not consummate an initial offering by October 24, 2009, Fertilizer GP can require us to purchase its managing general partner interest in the Partnership. We may not have requisite funds to do so.

If the Partnership does not consummate an initial private or public offering by October 24, 2009, Fertilizer GP can require us to purchase the managing general partner interest. This put right expires on the earlier of (1) October 24, 2012 and (2) the closing of the Partnership s initial offering. The purchase price will be the fair market value of the managing general partner interest, as determined by an independent investment banking firm selected by us and Fertilizer GP. Fertilizer GP will determine in its discretion whether the Partnership will consummate an initial offering.

If Fertilizer GP elects to require us to purchase the managing general partner interest, we may not have available cash resources to pay the purchase price. In addition, any purchase of the managing general partner interest would divert our capital resources from other intended uses, including capital expenditures and growth capital. In addition, the instruments governing our indebtedness may limit our ability to acquire, or prohibit us from acquiring, the managing general partner interest.

Fertilizer GP can require us to be a selling unit holder in the Partnership s initial offering at an undesirable time or price.

If Fertilizer GP elects to cause the Partnership to undertake an initial private or public offering, we have agreed that Fertilizer GP may structure the initial offering to include (1) a secondary offering of interests by us or (2) a primary offering of interests by the Partnership, possibly together with an incurrence of indebtedness by the Partnership, where a use of proceeds is to redeem units from us (with a per-unit redemption price equal to the price at which a unit is purchased from the Partnership, net of sales commissions or underwriting discounts) (a special GP offering), provided that in either case the number of units associated with the special GP offering is reasonably expected by Fertilizer GP to generate no more than $100 million in net proceeds to us. If Fertilizer GP elects to cause the Partnership to undertake an initial private or public offering, it may require us to sell (including by redemption) a portion, which could be a substantial portion, of our special units in the Partnership at a time or price we would not otherwise have chosen. A sale of special units would result in our receiving cash proceeds for the value of such units, net of sales commissions and underwriting discounts. Any such sale or redemption would likely result in taxable gain to us. See

Use of the limited partnership structure involves tax risks. For example, the Partnership s tax treatment depends on its status as a partnership for federal income tax purposes, as well as it not being subject to a material amount of

entity-level taxation by individual states. If the IRS were to treat the Partnership as a corporation for federal income tax purposes or if the Partnership were to become subject to additional amounts of entity-level taxation for state tax purposes, then its cash available for distribution to us would be substantially reduced.

Our rights to remove Fertilizer GP as managing general partner of the Partnership are extremely limited.

Until October 24, 2012, Fertilizer GP may only be removed as managing general partner if at least 80% of the outstanding units of the Partnership vote for removal and there is a final, non-appealable judicial determination that Fertilizer GP, as an entity, has materially breached a material provision of the partnership agreement or is liable for actual fraud or willful misconduct in its capacity as a general partner of the Partnership. Consequently, we will be unable to remove Fertilizer GP unless a court has made a final, non-appealable judicial determination in those limited circumstances as described above. Additionally, if there are other holders of partnership interests in the Partnership, these holders may have to vote for removal of Fertilizer GP as well if we desire to remove Fertilizer GP but do not hold at least 80% of the outstanding units of the Partnership at that time.

After October 24, 2012, Fertilizer GP may be removed with or without cause by a vote of the holders of at least 80% of the outstanding units of the Partnership, including any units owned by Fertilizer GP and its affiliates, voting together as a single class. Therefore, we may need to gain the support of other unitholders in the Partnership if we desire to remove Fertilizer GP as managing general partner, if we do not hold at least 80% of the outstanding units of the Partnership.

If the managing general partner is removed without cause, it will have the right to convert its managing general partner interest, including the IDRs, into units or to receive cash based on the fair market value of the interest at the time. If the managing general partner is removed for cause, a successor managing general partner will have the option to purchase the managing general partner interest, including the IDRs, of the departing managing general partner for a cash payment equal to the fair market value of the managing general partner interest. Under all other circumstances, the departing managing general partner will have the option to require the successor managing general partner to purchase the managing general partner interest of the departing managing general partner for its fair market value.

In addition to removal, we have a right to purchase Fertilizer GP s general partner interest in the Partnership, and therefore remove Fertilizer GP as managing general partner, if the Partnership has not made an initial private offering or an initial public offering of limited partner interests by October 24, 2012.

The nitrogen fertilizer business may not have sufficient cash to enable it to make quarterly distributions to us following the payment of expenses and fees and the establishment of cash reserves.

The nitrogen fertilizer business may not have sufficient cash each quarter to enable it to pay the minimum quarterly distribution or any distributions to us. The amount of cash the nitrogen fertilizer business can distribute on its units principally depends on the amount of cash it generates from its operations, which is primarily dependent upon the nitrogen fertilizer business selling quantities of nitrogen fertilizer at margins that are high enough to cover its fixed and variable expenses. The nitrogen fertilizer business costs, the prices it charges its customers, its level of production and, accordingly, the cash it generates from operations, will fluctuate from quarter to quarter based on, among other things, overall demand for its nitrogen fertilizer products, the level of foreign and

Table of Contents

domestic production of nitrogen fertilizer products by others, the extent of government regulation and overall economic and local market conditions. In addition:

The managing general partner of the nitrogen fertilizer business has broad discretion to establish reserves for the prudent conduct of the nitrogen fertilizer business. The establishment of those reserves could result in a reduction of the nitrogen fertilizer business distributions.

The amount of distributions made by the nitrogen fertilizer business and the decision to make any distribution are determined by the managing general partner of the Partnership, whose interests may be different from ours. The managing general partner of the Partnership has limited fiduciary and contractual duties, which may permit it to favor its own interests to our detriment.

Although the partnership agreement requires the nitrogen fertilizer business to distribute its available cash, the partnership agreement may be amended.

Any credit facility that the nitrogen fertilizer business enters into may limit the distributions which the nitrogen fertilizer business can make. In addition, any credit facility may contain financial tests and covenants that the nitrogen fertilizer business must satisfy. Any failure to comply with these tests and covenants could result in the lenders prohibiting distributions by the nitrogen fertilizer business.

The actual amount of cash available for distribution will depend on numerous factors, some of which are beyond the control of the nitrogen fertilizer business, including the level of capital expenditures made by the nitrogen fertilizer business, the nitrogen fertilizer business debt service requirements, the cost of acquisitions, if any, fluctuations in its working capital needs, its ability to borrow funds and access capital markets, the amount of fees and expenses incurred by the nitrogen fertilizer business, and restrictions on distributions and on the ability of the nitrogen fertilizer business to make working capital and other borrowings for distributions contained in its credit agreements.

If we were deemed an investment company under the Investment Company Act of 1940, applicable restrictions would make it impractical for us to continue our business as contemplated and could have a material adverse effect on our business. We may in the future be required to sell some or all of our partnership interests in order to avoid being deemed an investment company, and such sales could result in gains taxable to the company.

In order not to be regulated as an investment company under the Investment Company Act of 1940, as amended (the 1940 Act), unless we can qualify for an exemption, we must ensure that we are engaged primarily in a business other than investing, reinvesting, owning, holding or trading in securities (as defined in the 1940 Act) and that we do not own or acquire investment securities having a value exceeding 40% of the value of our total assets (exclusive of U.S. government securities and cash items) on an unconsolidated basis. We believe that we are not currently an investment company because our general partner interests in the Partnership should not be considered to be securities under the 1940 Act and, in any event, both our refinery business and the nitrogen fertilizer business are operated through majority-owned subsidiaries. In addition, even if our general partner interests in the Partnership were considered securities or investment securities, we believe that they do not currently have a value exceeding 40% of the fair market value of our total assets on an unconsolidated basis.

However, there is a risk that we could be deemed an investment company if the SEC or a court determines that our general partner interests in the Partnership are securities or investment securities under the 1940 Act and if our Partnership interests constituted more than 40% of the value of our total assets. Currently, our interests in the Partnership constitute less than 40% of our total assets on an unconsolidated basis, but they could constitute a higher percentage of the fair market value of our

total assets in the future if the value of our Partnership interests increases, the value of our other assets decreases, or some combination thereof occurs.

We intend to conduct our operations so that we will not be deemed an investment company. However, if we were deemed an investment company, restrictions imposed by the 1940 Act, including limitations on our capital structure and our ability to transact with affiliates, could make it impractical for us to continue our business as contemplated and could have a material adverse effect on our business and the price of our common stock. In order to avoid registration as an investment company under the 1940 Act, we may have to sell some or all of our interests in the Partnership at a time or price we would not otherwise have chosen. The gain on such sale would be taxable to us. We may also choose to seek to acquire additional assets that may not be deemed investment securities, although such assets may not be available at favorable prices. Under the 1940 Act, we may have only up to one year to take any such actions.

Use of the limited partnership structure involves tax risks. For example, the Partnership s tax treatment depends on its status as a partnership for federal income tax purposes, as well as it not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat the Partnership as a corporation for federal income tax purposes or if the Partnership were to become subject to additional amounts of entity-level taxation for state tax purposes, then its cash available for distribution to us would be substantially reduced.

The anticipated after-tax economic benefit of the Partnership s master limited partnership structure depends largely on its being treated as a partnership for U.S. federal income tax purposes. Despite the fact that the Partnership is organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as the Partnership to be treated as a corporation for U.S. federal income tax purposes. If the Partnership proceeds with an initial public offering, current law would require the Partnership to derive at least 90% of its annual gross income for the taxable year of such offering, and in each taxable year thereafter, from specific activities to continue to be treated as a partnership for U.S. federal income tax purposes. The Partnership may find it impossible to meet this 90% qualifying income requirement or may inadvertently fail to meet such income requirement.

To consummate an initial public offering, the Partnership will obtain an opinion of legal counsel that, based upon, among other things, customary representations by the Partnership, the Partnership will continue to be treated as a partnership for U.S. federal income tax purposes following such initial public offering. However, the ability of the Partnership to obtain such an opinion will depend upon a number of factors, including the state of the law at the time the Partnership seeks such an opinion and the specific facts and circumstances of the Partnership at such time. Therefore, there is no assurance that the Partnership will be able to obtain such an opinion and, thus, no assurance that we will be able to realize the anticipated benefits of the Partnership being a master limited partnership.

If the Partnership consummates an offering and we sell units, or our units are redeemed, in a special GP offering, or the Partnership makes a distribution to us of proceeds of the offering or debt financing, such sale, redemption or distribution would likely result in taxable gain to us. We will also recognize taxable gain to the extent that otherwise nontaxable distributions exceed our tax basis in the Partnership. The tax associated with any such taxable gain could be significant.

If an initial public offering is consummated, a subsequent change in the Partnership s business could cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject it to taxation as an entity. The Partnership is considering, and may consider in the future, expanding or entering into new activities or businesses. Gross income from any of these activities or businesses may not count toward satisfaction of the 90% qualifying income requirement for the Partnership to be treated as a partnership rather than as a corporation for U.S. federal income tax purposes.

Table of Contents

If the Partnership were to be treated as a corporation for U.S. federal income tax purposes, it would pay U.S. federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and would pay state income taxes at varying rates. Because such a tax would be imposed upon the Partnership as a corporation, the cash available for distribution by the Partnership to its partners, including us, would be substantially reduced. In addition, distributions by the Partnership to us would also be taxable to us (subject to the 70% or 80% dividends received deduction, as applicable, depending on the degree of ownership we have in the Partnership) and we would not be able to use our share of any tax losses of the Partnership to reduce taxes otherwise payable by us. Thus, treatment of the Partnership as a corporation could result in a material reduction in our anticipated cash flow and the after-tax return to us.

In addition, if an initial public offering is consummated, the law in effect at that time could change so as to cause the Partnership to be treated as a corporation for U.S. federal income tax purposes or otherwise subject it to entity-level taxation. For example, currently, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation as currently proposed would not apply to the Partnership, it could be amended prior to enactment in a manner that does apply to the Partnership. At the state level, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Specifically, beginning in 2008, the Partnership is required to pay Texas franchise tax at a maximum effective rate of 0.7% of its gross income apportioned to Texas in the prior year. Imposition of this tax by Texas and, if applicable, by any other state will reduce the Partnership s cash available for distribution by the Partnership. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could result in a material reduction in our anticipated cash flow and the after-tax return to us.

In addition, the sale of the managing general partner interest of the Partnership to an entity controlled by the Goldman Sachs Funds and the Kelso Funds was made at the fair market value of such general partner interest as of the date of transfer, as determined by our board of directors after consultation with management. Any gain on this sale by us is subject to tax. If the IRS or another taxing authority successfully asserted that the fair market value at the time of sale of the managing general partner interest exceeded the sale price, we would have additional deemed taxable income which could reduce our cash flow and adversely affect our financial results. For example, if the value of the managing general partner interest increases over time, possibly significantly because the Partnership performs well, then in hindsight the sale price might be challenged or viewed as insufficient by the IRS or another taxing authority.

Additionally, when the Partnership issues units to new unitholders or engages in certain other transactions, the Partnership will determine the fair market value of its assets and allocate any unrealized gain or loss attributable to those assets to the capital accounts of the existing partners. As a result of this revaluation and the Partnership s adoption of the remedial allocation method under Section 704(c) of the Internal Revenue Code (i) new unitholders will be allocated deductions as if the tax basis of the Partnership s property were equal to the fair market value thereof at the time of the offering, and (ii) we will be allocated reverse Section 704(c) allocations of income or loss over time consistent with our allocation of unrealized gain or loss.

Fertilizer GP s interest in the Partnership and the control of Fertilizer GP may be transferred to a third party without our consent. the new owners of Fertilizer GP may have no Interest in CVR Energy and may take actions that are not in our interest.

Fertilizer GP is currently controlled by the Goldman Sachs Funds and the Kelso Funds. The Goldman Sachs Funds and the Kelso Funds will also collectively beneficially own approximately 61.4% of our common stock following the completion of this offering (59.7% if the underwriters exercise their option to purchase additional shares in full). Fertilizer GP may transfer its managing general partner interest in the Partnership to a third party in a merger or in a sale of all or substantially all of its assets without our consent. Furthermore, there is no restriction in the partnership agreement

on the ability of the current owners of Fertilizer GP to transfer their equity interest in Fertilizer GP to a third party. The new equity owner of Fertilizer GP would then be in a position to replace the board of directors (other than the two directors appointed by us) and the officers of Fertilizer GP (subject to our joint rights in relation to the chief executive officer and chief financial officer) with its own choices and to influence the decisions taken by the board of directors and officers of Fertilizer GP. These new equity owners, directors and executive officers may take actions, subject to the specified joint management rights we have as a holder of special GP rights, which are not in our interests or the interests of our stockholders. In particular, the new owners may have no economic interest in us (unlike the current owners of Fertilizer GP), which may make it more likely that they would take actions to benefit Fertilizer GP and its managing general partner interest over us and our interests in the Partnership.

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements. We claim the protection of the safe harbor for forward-looking statements provided in the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Statements that are predictive in nature, that depend upon or refer to future events or conditions or that include the words believe, expect, anticipate, intend, estimate and oth expressions that are predictions of or indicate future events and trends and that do not relate to historical matters identify forward-looking statements. Our forward-looking statements include statements about our business strategy, our industry, our future profitability, our expected capital expenditures and the impact of such expenditures on our performance, the costs of operating as a public company, our capital programs and environmental expenditures. These statements involve known and unknown risks, uncertainties and other factors, including the factors described under Risk Factors , that may cause our actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. Such risks and uncertainties include, among other things:

- volatile margins in the refining industry;
- exposure to the risks associated with volatile crude prices;
- the availability of adequate cash and other sources of liquidity for our capital needs;
- disruption of our ability to obtain an adequate supply of crude oil;
- losses due to the Cash Flow Swap;
- decreases in the light/heavy and/or the sweet/sour crude oil price spreads;
- losses, damages and lawsuits related to the flood and crude oil discharge;
- the failure of our new and redesigned equipment in our facilities to perform according to expectations;
- interruption of the pipelines supplying feedstock and in the distribution of our products;
- the seasonal nature of our petroleum business;
- competition in the petroleum and nitrogen fertilizer businesses;
- capital expenditures required by environmental laws and regulations;
- changes in our credit profile;
- the potential decline in the price of natural gas, which historically has correlated with the market price for nitrogen fertilizer products;
- the cyclical nature of the nitrogen fertilizer business;
- adverse weather conditions, including potential floods;

the supply and price levels of essential raw materials;

the volatile nature of ammonia, potential liability for accidents involving ammonia that cause severe damage to property and/or injury to the environment and human health and potential increased costs relating to transport of ammonia;

the dependence of the nitrogen fertilizer operations on a few third-party suppliers;

the reliance of the nitrogen fertilizer business on third-party providers of transportation services and equipment;

environmental laws and regulations affecting the end-use and application of fertilizers;

a decrease in ethanol production;

the potential loss of the nitrogen fertilizer business transportation cost advantage over its competitors;

refinery operating hazards and interruptions, including unscheduled maintenance or downtime, and the availability of adequate insurance coverage;

our commodity derivative activities;

uncertainty regarding our ability to recover costs and losses resulting from the flood and crude oil discharge;

our limited operating history as a stand-alone company;

our dependence on significant customers;

our potential inability to successfully implement our business strategies, including the completion of significant capital programs;

the success of our acquisition and expansion strategies;

the dependence on our subsidiaries for cash to meet our debt obligations;

our significant indebtedness;

whether we will be able to amend our credit facility on acceptable terms if the Partnership seeks to consummate a public or private offering;

the potential loss of key personnel;

labor disputes and adverse employee relations;

potential increases in costs and distraction of management resulting from the requirements of being a public company;

risks relating to evaluations of internal controls required by Section 404 of the Sarbanes-Oxley Act;

the operation of our company as a controlled company ;

new regulations concerning the transportation of hazardous chemicals, risks of terrorism and the security of chemical manufacturing facilities;

successfully defending against third-party claims of intellectual property infringement;

our ability to continue to license the technology used in our operations;

the Partnership s ability to make distributions equal to the minimum quarterly distribution or any distributions at all;

the possibility that Partnership distributions to us will decrease if the Partnership issues additional equity interests and that our rights to receive distributions will be subordinated to the rights of third party investors;

the possibility that we will be required to deconsolidate the Partnership from our financial statements in the future;

the Partnership s preferential right to pursue certain business opportunities before we pursue them;

reduction of our voting power in the Partnership if the Partnership completes a public offering or private placement;

whether we will be required to purchase the managing general partner interest in the Partnership, and whether we will have the requisite funds to do so;

the possibility that we will be required to sell a portion of our interests in the Partnership in the Partnership s initial offering at an undesirable time or price;

the ability of the Partnership to manage the nitrogen fertilizer business in a manner adverse to our interests;

the conflicts of interest faced by our senior management, which operates both our company and the Partnership, and our controlling stockholders, who control our company and the managing general partner of the Partnership;

limitations on the fiduciary duties owed by the managing general partner which are included in the partnership agreement;

whether we are ever deemed to be an investment company under the 1940 Act or will need to take actions to sell interests in the Partnership or buy assets to refrain from being deemed an investment company;

changes in the treatment of the Partnership as a partnership for U.S. income tax purposes;

transfer of control of the managing general partner of the Partnership to a third party that may have no economic interest in us; and

the risk that the Partnership will not consummate a public offering or private placement.

You should not place undue reliance on our forward-looking statements. Although forward-looking statements reflect our good faith beliefs, reliance should not be placed on forward-looking statements because they involve known and unknown risks, uncertainties and other factors, which may cause our actual results, performance or achievements to differ materially from anticipated future results, performance or achievements expressed or implied by such forward-looking statements. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changed circumstances or otherwise.

USE OF PROCEEDS

We will not receive any of the proceeds from sale of shares of our common stock by the selling stockholders. Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC intend to distribute the net proceeds, after giving effect to the underwriting discount, from the sale of shares of our common stock to their members, which includes certain members of our senior management team. See Principal and Selling Stockholders.

Table of Contents

DIVIDEND POLICY

We do not anticipate paying any cash dividends in the foreseeable future. We currently intend to retain future earnings from our refinery business, if any, together with any cash distributions we receive from the Partnership, to finance operations and the expansion of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors and will be dependent upon our financial condition, results of operations, capital requirements and other factors that the board deems relevant. In addition, the covenants contained in our credit facility limit the ability of our subsidiaries to pay dividends to us, which limits our ability to pay dividends to our stockholders, including any amounts received from the Partnership in the form of quarterly distributions. Our ability to pay dividends also may be limited by covenants in other instruments governing future indebtedness that we or our subsidiaries may incur in the future. See Description of Our Indebtedness and the Cash Flow Swap.

In addition, the partnership agreement which governs the Partnership includes restrictions on the Partnership s ability to make distributions to us. If the Partnership issues limited partner interests to third party investors, these investors will have rights to receive distributions which, in some cases, will be senior to our rights to receive distributions. In addition, the managing general partner of the Partnership has incentive distribution rights which, over time, will give it rights to receive distributions. These provisions will limit the amount of distributions which the Partnership can make to us which will, in turn, limit our ability to make distributions to our stockholders. In addition, since the Partnership will make its distributions to Coffeyville Resources, LLC, a subsidiary of ours, our credit facility will limit the ability of Coffeyville Resources, LLC to distribute these distributions to us. In addition, the Partnership may also enter into its own credit facility or other contracts that limit its ability to make distributions to us.

In October 2007, the directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, respectively, approved a special dividend of $10.6 million to their members, including approximately $5.2 million to the Goldman Sachs Funds, approximately $5.1 million to the Kelso Funds and approximately $0.3 million to certain members of our senior management team, a director and an unrelated member. The common unit holders receiving this special dividend contributed $10.6 million collectively to Coffeyville Acquisition III LLC, which used such amounts to purchase the managing general partner of the Partnership.

Table of Contents

MARKET PRICE OF OUR COMMON STOCK

Our common stock has been listed on the New York Stock Exchange under the symbol CVI since October 23, 2007. Prior to that time, there was no public market for our common stock. The following table sets forth for the periods indicated the high and low reported sale prices per share of our common stock on the New York Stock Exchange. These prices do not include retail markups, markdowns or commissions.

	High	Low
Year Ended December 31, 2007:		
Fourth Quarter (from October 23, 2007)	$ 26.25	$ 19.80
Year Ending December 31, 2008:		
First Quarter	30.94	20.71
Second Quarter (through June 17, 2008)	28.88	19.57

A recent reported closing price for our common stock is set forth on the cover page of this prospectus. American Stock Transfer & Trust Company is the registrar and transfer agent for our common stock. We estimate that there were approximately 451 holders of record of our common stock as of June 16, 2008. Because many of our shares of common stock are held by brokers and other institutions on behalf of stockholders, we are unable to estimate the total number of stockholders represented by these record holders.

Table of Contents

CAPITALIZATION

The following table sets forth our consolidated cash and cash equivalents and capitalization as of March 31, 2008:

on an actual basis;

on an adjusted basis to give effect to (a) the proposed $25.0 million senior secured credit facility, (b) certain expenses associated with this offering and (c) the Phantom Unit Plans payment of $3.5 million (assuming the underwriters option is not exercised) by us to members of our senior management team as a result of this offering, as if each had occurred on March 31, 2008; and

on an as further adjusted basis to give effect to (a), (b) and (c) above as well as (d) our concurrent offering of $125.0 million aggregate principal amount of our Convertible Senior Notes due 2013 (assuming the underwriters option is not exercised), as if each had occurred on March 31, 2008. The consummation of this equity offering is not conditioned upon the consummation of our concurrent offering of Convertible Senior Notes due 2013 and vice versa.

You should read this table in conjunction with Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations, and the consolidated financial statements and related notes included elsewhere in this prospectus.

	As of March 31, 2008		
	Actual	As Adjusted (unaudited) (in thousands)	Further Adjusted for Convertible Offering (unaudited)
Cash and cash equivalents	$ 25,179	$	$
Debt (including current portion):			
Revolving credit facility(1)	$	$	$
Term loan facility	487,979		
Proposed senior secured credit facility			
Convertible senior notes due 2013			
Total debt	487,979		
Minority interest in subsidiaries(2)	10,600		
Stockholders equity:			
Common stock, $0.01 par value per share, 350,000,000 shares authorized; 86,141,291 shares issued and outstanding	861		
Preferred stock, $0.01 par value per share, 50,000,000 shares authorized; no shares issued and outstanding			
Additional paid-in-capital	458,523		

Retained earning (deficit)	(4,279)		
Total stockholders equity	455,105		
Total capitalization	$ 953,684	$	$

(1) As of June 16, 2008, we had availability of $112.6 million under our revolving credit facility.

(2) Represents the managing general partner s interest in the Partnership held by Coffeyville Acquisition III LLC.

Table of Contents

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The historical data presented below has been derived from financial statements that have been prepared using GAAP and that are included elsewhere in this prospectus. You should read the selected historical consolidated financial data presented below in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the related notes included elsewhere in this prospectus.

The selected consolidated financial information presented below under the caption Statement of Operations Data for the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005 and the years ended December 31, 2006 and 2007 and the selected consolidated financial information presented below under the caption Balance Sheet Data as of December 31, 2006 and 2007 has been derived from our audited consolidated financial statements included elsewhere in this prospectus, which financial statements have been audited by KPMG LLP, independent registered public accounting firm. The consolidated financial information presented below under the caption Statement of Operations Data for the year ended December 31, 2003, the 62-day period ended March 2, 2004 and the 304 days ended December 31, 2004, and the consolidated financial information presented below under the caption Balance Sheet Data at December 31, 2003, 2004 and 2005, are derived from our audited consolidated financial statements that are not included in this prospectus. The selected unaudited interim consolidated financial information presented below under the caption Statement of Operations Data presented below for the three month period ended March 31, 2007 and the three month period ended March 31, 2008, and the selected unaudited interim consolidated financial information presented below under the caption Balance Sheet Data as of March 31, 2008, have been derived from our unaudited interim consolidated financial statements, which are included elsewhere in this prospectus and have been prepared on the same basis as the audited consolidated financial statements. In the opinion of management, the interim data reflect all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of results for these periods. Operating results for the three month period ended March 31, 2008 are not necessarily indicative of the results that may be expected for the year ending December 31, 2008.

Prior to March 3, 2004, our assets were operated as a component of Farmland. We refer to our operations as part of Farmland during this period as Original Predecessor . Farmland filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 31, 2002. On March 3, 2004, Coffeyville Resources, LLC completed the purchase of Original Predecessor from Farmland in a sales process under Chapter 11 of the U.S. Bankruptcy Code. See Note 1 to our consolidated financial statements included elsewhere in this prospectus. We refer to this acquisition as the Initial Acquisition, and we refer to our post-Farmland operations run by Coffeyville Group Holdings, LLC as Immediate Predecessor. Our business was operated by the Immediate Predecessor for the 304 days ended December 31, 2004 and the 174 days ended June 23, 2005. As a result of certain adjustments made in connection with the Initial Acquisition, a new basis of accounting was established on the date of the Initial Acquisition and the results of operations for the 304 days ended December 31, 2004 are not comparable to prior periods. During periods when we were operated as part of Farmland, which include the fiscal year ended December 31, 2003 and the 62 days ended March 2, 2004, Farmland allocated certain general corporate expenses and interest expense to Original Predecessor. The allocation of these costs is not necessarily indicative of the costs that would have been incurred if Original Predecessor had operated as a stand-alone entity. Further, the historical results are not necessarily indicative of the results to be expected in future periods.

We calculate earnings per share for the years ended December 31, 2006 and 2007 and the three month period ended March 31, 2007 on a pro forma basis, assuming our post-IPO capital structure had been in place for the entire year for each of 2006 and 2007. For the year ended December 31, 2007, 17,500 non-vested common shares and 18,900 common stock options have been excluded from the calculation of pro forma diluted earnings per share because the inclusion of such common stock equivalents in the number of weighted average shares outstanding would be anti-dilutive. We have omitted earnings per share data for Immediate Predecessor because we operated under a different capital structure than our current capital structure and, therefore, the information is not meaningful.

We have omitted per share data for Original Predecessor because, under Farmland s cooperative structure, earnings of Original Predecessor were distributed as patronage dividends to members and associate members based on the level of business conducted with Original Predecessor as opposed to a common stockholder s proportionate share of underlying equity in Original Predecessor.

Original Predecessor was not a separate legal entity, and its operating results were included with the operating results of Farmland and its subsidiaries in filing consolidated federal and state income tax returns. As a cooperative, Farmland was subject to income taxes on all income not distributed to patrons as qualifying patronage refunds and Farmland did not allocate income taxes to its divisions. As a result, Original Predecessor periods do not reflect any provision for income taxes.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. See Note 1 to our consolidated financial statements included elsewhere in this prospectus. We refer to this acquisition as the Subsequent Acquisition, and we refer to our post-June 24, 2005 operations as Successor. As a result of certain adjustments made in connection with the Subsequent Acquisition, a new basis of accounting was established on the date of the acquisition. Since the assets and liabilities of Successor and Immediate Predecessor were each presented on a new basis of accounting, the financial information for Successor, Immediate Predecessor and Original Predecessor is not comparable.

Financial data for the 2005 fiscal year is presented as the 174 days ended June 23, 2005 and the 233 days ended December 31, 2005. Successor had no financial statement activity during the period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil, and gasoline option agreements entered into with a related party as of May 16, 2005.

On April 23, 2008, the audit committee of our board of directors and management concluded that our previously issued consolidated financial statements for the year ended December 31, 2007 and the related quarter ended September 30, 2007 contained errors. See footnote 2 to our consolidated financial statements for the year ended December 31, 2007 included elsewhere in this prospectus and Management s Discussion and Analysis of Financial Condition and Results of Operations Restatement of Year Ended December 31, 2007 and Quarter Ended September 30, 2007 Financial Statements. All information presented in this prospectus reflects our restated financial results.

	Successor	
	Three Months Ended March 31, 2007	Three Months Ended March 31, 2008
	(unaudited) (in millions, unless otherwise indicated)	
Statement of Operations Data:		
Net sales	$ 390.5	$ 1,223.0
Cost of product sold (exclusive of depreciation and amortization)	303.7	1,036.2
Direct operating expenses (exclusive of depreciation and amortization)	113.4	60.6
Selling, general and administrative expenses (exclusive of depreciation and amortization)	13.2	13.4
Net costs associated with flood(1)		5.8
Depreciation and amortization(2)	14.2	19.6
Operating income (loss)	(54.0)	87.4
Other income, net	0.5	0.9
Interest expense and other financing costs	(11.9)	(11.3)
Loss on derivatives, net	(137.0)	(47.9)
Income (loss) before income taxes and minority interests in subsidiaries	(202.4)	29.1
Income tax (expense) benefit	(47.3)	(6.9)
Minority interest in (income) loss of subsidiaries	0.7	
Net income (loss)(3)	(154.4)	22.2
Pro forma earnings (loss) per share, basic	(1.79)	
Pro forma earnings (loss) per share, diluted	(1.79)	
Pro forma weighted average shares, basic	86,141,291	
Pro forma weighted average shares, diluted	86,141,291	
Earnings per share, basic		0.26
Earnings per share, diluted		0.26
Weighted average shares, basic		86,141,291
Weighted average shares, diluted		86,158,791
Balance Sheet Data:		
Cash and cash equivalents		25.2
Working capital		21.5
Total assets		1,923.6
Total debt, including current portion		499.2
Minority interest in subsidiaries		10.6
Stockholders equity		455.1
Other Financial Data:		
Depreciation and amortization(2)	14.2	19.6
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	(82.4)	30.6
Cash flows provided by operating activities	44.1	24.2
Cash flows (used in) investing activities	(107.4)	(26.2)
Cash flows provided by (used in) financing activities	29.0	(3.4)

Capital expenditures for property, plant and equipment		107.4		26.2
Key Operating Statistics:				
Petroleum Business				
Production (barrels per day)(5)		53,689		125,614
Crude oil throughput (barrels per day)(5)		47,267		106,530
Refining margin per crude oil throughput barrel (dollars)(6)	$	12.69	$	13.76
NYMEX 2-1-1 crack spread (dollars)(7)	$	12.17	$	11.81
Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel (dollars)(8)	$	22.73	$	4.16
Gross profit (loss) per crude oil throughput per barrel (dollars)(8)	$	(12.34)	$	7.50
Nitrogen Fertilizer Business				
Production Volume:				
Ammonia (tons in thousands)		86.2		83.7
UAN (tons in thousands)		165.7		150.1
On-stream factors:				
Gasification		91.8%		91.8%
Ammonia		86.3%		90.7%
UAN		89.4%		85.9%

Table of Contents

	Original Predecessor		Immediate Predecessor			Successor	
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Yea End Decemb 200
			(in millions, unless otherwise indicated)				
nt of Operations Data:							
	$ 1,262.2	$ 261.1	$ 1,479.9	$ 980.7	$ 1,454.3	$ 3,037.6	$ 2
roduct sold (exclusive of ion and amortization)	1,061.9	221.4	1,244.2	768.0	1,168.1	2,443.4	2
erating expenses (exclusive of ion and amortization)	133.1	23.4	117.0	80.9	85.3	199.0	
eneral and administrative (exclusive of depreciation and ion)	23.6	4.7	16.3	18.4	18.4	62.6	
associated with flood(1)							
ion and amortization(2)	3.3	0.4	2.4	1.1	24.0	51.0	
nt, earnings (losses) in joint and other charges(9)	10.9						
g income	$ 29.4	$ 11.2	$ 100.0	$ 112.3	$ 158.5	$ 281.6	$
ome (expense)(10)	(0.5)		(6.9)	(8.4)	0.4	(20.8)	
xpense)	(1.3)		(10.1)	(7.8)	(25.0)	(43.9)	
s) on derivatives	0.3		0.5	(7.6)	(316.1)	94.5	
oss) before income taxes	$ 27.9	$ 11.2	$ 83.5	$ 88.5	$ (182.2)	$ 311.4	$
ax (expense) benefit			(33.8)	(36.1)	63.0	(119.8)	
interest in (income) loss of es							
ne (loss)(3)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$
a earnings per share, basic						$ 2.22	$
a earnings per share, diluted						$ 2.22	$
a weighted average shares, basic						86,141,291	86,14
a weighted average shares,						86,158,791	86,14
l dividends:							
per unit(11)			$ 1.50	$ 0.70			
per unit(11)			$ 0.48	$ 0.70			
nent common units subject to on						$ 3.1	
units						$ 246.9	
Sheet Data:							
cash equivalents	$ 0.0		$ 52.7		$ 64.7	$ 41.9	$
capital(12)	150.5		106.6		108.0	112.3	
ets	199.0		229.2		1,221.5	1,449.5	1
s subject to compromise(13)	105.2						

t, including current portion			148.9		499.4	775.0	
interest in subsidiaries(14)						4.3	
nent units subject to redemption					3.7	7.0	
l/members /stockholders equity	58.2		14.1		115.8	76.4	
nancial Data:							
ion and amortization	$ 3.3	$ 0.4	$ 2.4	$ 1.1	$ 24.0	$ 51.0	$
ne (loss) adjusted for unrealized ss from Cash Flow Swap(4)	27.9	11.2	49.7	52.4	23.6	115.4	
vs provided by operating	20.3	53.2	89.8	12.7	82.5	186.6	
vs (used in) investing activities	(0.8)		(130.8)	(12.3)	(730.3)	(240.2)	
vs provided by (used in) activities	(19.5)	(53.2)	93.6	(52.4)	712.5	30.8	
xpenditures for property, plant pment	0.8		14.2	12.3	45.2	240.2	
rating Statistics:							
m Business							
on (barrels per day)(5)(15)	95,701	106,645	102,046	99,171	107,177	108,031	
throughput (barrels per 5)	85,501	92,596	90,418	88,012	93,908	94,524	
margin per crude oil throughput llars)(6)	$ 3.89	$ 4.23	$ 5.92	$ 9.28	$ 11.55	$ 13.27	$
2-1-1 crack spread (dollars)(7)	$ 5.53	$ 6.80	$ 7.55	$ 9.60	$ 13.47	$ 10.84	$
erating expenses (exclusive of ion and amortization) per crude hput barrel (dollars)(8)	$ 2.57	$ 2.60	$ 2.66	$ 3.44	$ 3.13	$ 3.92	$
fit (loss) per crude oil ut per barrel (dollars)(8)	$ 1.25	$ 1.57	$ 3.20	$ 5.79	$ 7.55	$ 8.39	$
Fertilizer Business							
n Volume:							
a (tons in thousands)(15)	335.7	56.4	252.8	193.2	220.0	369.3	
s in thousands)(15)	510.6	93.4	439.2	309.9	353.4	633.1	
factors (16):							
	90.1%	93.5%	92.2%	97.4%	98.7%	92.5%	
a	89.6%	80.9%	79.7%	95.0%	98.3%	89.3%	
	81.6%	88.7%	82.2%	93.9%	94.8%	88.9%	

(1) Represents the write-off of approximate net costs associated with the flood and crude oil spill that are not probable of recovery. See Flood and Crude Oil Discharge .

(2) Depreciation and amortization is comprised of the following components as excluded from cost of product sold, direct operating expenses and selling, general and administrative expenses:

72

Table of Contents

	Original Predecessor		Immediate Predecessor			Successor			
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
	(in millions)								
Depreciation and amortization included in cost of product sold	$	$	$ 0.2	$ 0.1	$ 1.1	$ 2.2	$ 2.4	$ 0.6	$ 0.6
Depreciation and amortization included in direct operating expense	3.3	0.4	2.2	0.9	22.7	47.7	57.4	13.5	18.7
Depreciation and amortization included in selling, general and administrative expense			0.2	0.1	0.2	1.1	1.0	0.1	0.3
Depreciation and amortization included in net costs associated with flood							7.6		
Total depreciation and amortization	$ 3.3	$ 0.4	$ 2.4	$ 1.1	$ 24.0	$ 51.0	$ 68.4	$ 14.2	$ 19.6

(3) The following are certain charges and costs incurred in each of the relevant periods that are meaningful to understanding our net income and in evaluating our performance due to their unusual or infrequent nature:

	Original Predecessor		Immediate Predecessor			Successor			
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
	(in millions)								
Impairment of property, plant and	$ 9.6	$	$	$	$	$	$	$	$

equipment(a)							
Loss on extinguishment of debt(b)	7.2	8.1		23.4	1.3		
Inventory fair market value adjustment(c)	3.0		16.6				
Funded letter of credit expense and interest rate swap not included in interest expense(d)			2.3		1.8		0.9
Major scheduled turnaround expense(e)	1.8			6.6	76.4	66.0	
Loss on termination of swap(f)			25.0				
Unrealized (gain) loss from Cash Flow Swap			235.9	(126.8)	103.2	119.7	13.9

(a) During the year ended December 31, 2003, we recorded a charge of $9.6 million related to the asset impairment of our refinery and nitrogen fertilizer plant based on the expected sales price of the assets in the Initial Acquisition.

(b) Represents the write-off of: (i) $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004, (ii) $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005, (iii) $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006 and (iv) $1.3 million in connection with the repayment and termination of three credit facilities on October 26, 2007.

(c) Consists of the additional cost of product sold expense due to the step up to estimated fair value of certain inventories on hand at March 3, 2004 and June 24, 2005, as a result of the allocation of the purchase price of the Initial Acquisition and the Subsequent Acquisition to inventory.

(d) Consists of fees which are expensed to selling, general and administrative expenses in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. We consider these fees to be equivalent to interest expense and the fees are treated as such in the calculation of EBITDA in the credit facility.

(e) Represents expense associated with a major scheduled turnaround.

(f) Represents the expense associated with the expiration of the crude oil, heating oil and gasoline option agreements entered into by Coffeyville Acquisition LLC in May 2005.

Table of Contents

(4) Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the unrealized portion of the derivative transaction that was executed in conjunction with the acquisition of Coffeyville Group Holdings, LLC by Coffeyville Acquisition LLC on June 24, 2005. On June 16, 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned by Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not as a percentage of crude oil prices) crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010, so long as at the time of reduction or termination, we pay the amount of unrealized losses associated with the amount reduced or terminated. See Description of our Indebtedness and the Cash Flow Swap.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect in each period material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements, which is accounted for as a liability on our balance sheet. As the absolute crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our statement of operations. Conversely, as absolute crack spreads decline we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our board of directors considers our GAAP net income results as well as Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our performance but instead should be utilized as a supplemental measure of financial performance or liquidity in evaluating our business. Because Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our Cash Flow Swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

The following is a reconciliation of Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap to Net income (loss):

	Original Predecessor	Immediate Predecessor			Successor				
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
				(in millions)					
Net income (loss) adjusted for unrealized gain (loss) from Cash Flow Swap	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ 23.6	$ 115.4	$ (5.6)	$ (82.4)	$ 30.6
Plus: Unrealized gain (loss) from Cash Flow Swap, net of tax benefit					(142.8)	76.2	(62.0)	(72.0)	(8.4)
Net income (loss)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ (67.6)	$ (154.4)	$ 22.2

(5) Barrels per day is calculated by dividing the volume in the period by the number of calendar days in the period. Barrels per day as shown here is impacted by plant down-time and other plant disruptions and does not represent the capacity of the facility s continuous operations.

(6) Refining margin per crude oil throughput barrel is a measurement calculated as the difference between net sales and cost of product sold (exclusive of depreciation and amortization) divided by the refinery s crude oil throughput volumes for the respective periods presented. Refining margin per crude oil throughput barrel is a non-GAAP measure that should not be substituted for gross profit or operating income and that we believe is important to investors in evaluating our refinery s performance as a general indication of the amount above our cost of product sold that we are able to sell refined products. Our calculation of refining margin per crude oil throughput barrel may differ from similar calculations of other companies in our industry, thereby limiting its usefulness as a comparative measure. We use refining margin per crude oil throughput barrel as the most direct and comparable metric to a crack spread which is an observable market indication of industry profitability.

The table included in footnote 8 reconciles refining margin per crude oil throughput barrel to gross profit for the periods presented.

(7) This information is industry data and is not derived from our audited financial statements or unaudited interim financial statements.

(8) Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel is calculated by dividing direct operating expenses (exclusive of depreciation and amortization) by total crude oil throughput volumes for the respective periods presented. Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel includes costs associated with the actual operations of the refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance and labor and environmental compliance costs but does not include depreciation or amortization. We use direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel as a measure of operating efficiency within the plant and as a control metric for expenditures.

Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel is a non-GAAP measure. Our calculations of direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel may differ from similar calculations of other companies in our industry, thereby limiting its usefulness as a comparative measure. The following table reflects direct operating expenses (exclusive of depreciation and amortization) and the related calculation of direct operating expenses per crude oil throughput barrel:

	Historical								
	Original Predecessor		Immediate Predecessor		Successor				
	Year Ended December 31, 2003	62 Days Ended March 2, 2004	304 Days Ended December 31, 2004	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	Three Month Ended March 3 2008 (unaudit
	(in millions, except as otherwise indicated)								
roleum Business:									
Sales	$ 1,161.3	$ 241.6	$ 1,390.8	$ 903.8	$ 1,363.4	$ 2,880.4	$ 2,806.2	$ 352.5	$ 1,168
t of product sold clusive of reciation and ortization)	1,040.0	217.4	1,228.1	761.7	1,156.2	2,422.7	2,300.2	298.5	1,035
ect operating enses (exclusive of reciation and ortization)	80.1	14.9	73.2	52.6	56.2	135.3	209.5	96.7	40
costs associated h flood							36.7		5
reciation and ortization	2.1	0.3	1.5	0.8	15.6	33.0	43.0	9.8	14
ss profit (loss)	$ 39.1	$ 9.0	$ 88.0	$ 88.7	$ 135.4	$ 289.4	$ 216.8	$ (52.5)	$ 72
s direct operating enses (exclusive of reciation and ortization)	80.1	14.9	73.2	52.6	56.2	135.3	209.5	96.7	40
							36.7		5

s net costs ociated with flood s depreciation and ortization		2.1		0.3		1.5		0.8		15.6		33.0		43.0		9.8	14
ining margin	$	121.3	$	24.2	$	162.7	$	142.1	$	207.2	$	457.7	$	506.0	$	54.0	$ 133
ining margin per de oil throughput el (dollars)	$	3.89	$	4.23	$	5.92	$	9.28	$	11.55	$	13.27	$	18.17	$	12.69	$ 13.
ss profit (loss) per de oil throughput el (dollars)	$	1.25	$	1.57	$	3.20	$	5.79	$	7.55	$	8.39	$	7.79	$	(12.34)	$ 7.
ect operating enses (exclusive of reciation and ortization) per de oil throughput el (dollars)	$	2.57	$	2.60	$	2.66	$	3.44	$	3.13	$	3.92	$	7.52	$	22.73	$ 4.
rating income s)		21.5		7.7		77.1		76.7		123.0		245.6		144.9		(63.5)	63

(9) During the year ended December 31, 2003, we recorded an additional charge of $9.6 million related to the asset impairment of the refinery and fertilizer plant based on the expected sales price of the assets in the Initial Acquisition. In addition, we recorded a charge of $1.3 million for the rejection of existing contracts while operating under Chapter 11 of the U.S. Bankruptcy Code.

(10) During the 304 days ended December 31, 2004, the 174 days ended June 23, 2005, the year ended December 31, 2006 and the year ended December 31, 2007, we recognized a loss of $7.2 million, $8.1 million, $23.4 million and $1.3 million, respectively, on early extinguishment of debt.

(11) Historical dividends per unit for the 304-day period ended December 31, 2004 and the 174-day period ended June 23, 2005 are calculated based on the ownership structure of Immediate Predecessor.

(12) Excludes liabilities subject to compromise due to Original Predecessor s bankruptcy of $105.2 million as of December 31, 2003 in calculating Original Predecessor s working capital.

(13) While operating under Chapter 11 of the U.S. Bankruptcy Code, Original Predecessor s financial statements were prepared in accordance with SOP 90-7, Financial Reporting by Entities in Reorganization under the Bankruptcy Code. SOP 90-7 requires that pre-petition liabilities be segregated in the balance sheet.

(14) Minority interest reflects common stock in two of our subsidiaries owned by John J. Lipinski (which were exchanged for shares of our common stock with an equivalent value prior to the consummation of our initial public offering). Minority interest at December 31, 2007 reflects Coffeyville Acquisition III LLC s ownership of the managing general partner interest and IDRs of the Partnership.

(15) Operational information reflected for the 233-day Successor period ended December 31, 2005 includes only 191 days of operational activity. Successor was formed on May 13, 2005 but had no financial statement activity during the 42-day period from May 13, 2005 to June 24, 2005, with the exception of certain crude oil, heating oil and gasoline option agreements entered into with J. Aron as of May 16, 2005 which expired unexercised on June 16, 2005.

(16) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period. Excluding the impact of turnarounds at the nitrogen fertilizer facility in the third quarter of 2004 and 2006, (i) the on-stream factors for the year ended December 31, 2004 would have been 95.6% for gasifier, 83.1% for ammonia and 86.7% for UAN and (ii) the on-stream factors for the year ended December 31, 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN. Excluding the impact of the flood during the weekend of June 30, 2007, the on-stream factors for the year ended December 31, 2007 would have been 94.6% for gasifier, 92.4% for ammonia and 83.9% for UAN.

Table of Contents

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

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with our financial statements and related notes included elsewhere in this prospectus. This discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including, but not limited to, those set forth under Risk Factors, Cautionary Note Regarding Forward-Looking Statements and elsewhere in this prospectus.

Overview and Executive Summary

We are an independent refiner and marketer of high value transportation fuels. In addition, we currently own all of the interests (other than the managing general partner interest and associated IDRs) in a limited partnership which produces the nitrogen fertilizers ammonia and UAN. At current natural gas and pet coke prices, the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN in North America.

We operate under two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2005, 2006 and 2007, we generated combined net sales of $2.4 billion, $3.0 billion and $3.0 billion, respectively. Our petroleum business generated $2.3 billion, $2.9 billion and $2.8 billion of our combined net sales, respectively, over these periods, with the nitrogen fertilizer business generating substantially all of the remainder. In addition, during these periods, our petroleum business contributed 74%, 87% and 78% of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder. For the three months ended March 31, 2008, we generated combined net sales of $1.22 billion, with the petroleum business generating $1.17 billion of our combined net sales, and the nitrogen fertilizer business generating substantially all of the remainder. For the same period, the petroleum business contributed 73% of our combined operating income and the nitrogen fertilizer business generated substantially all of the remainder.

Petroleum Business. Our petroleum business includes a 115,000 bpd complex full coking medium-sour crude refinery in Coffeyville, Kansas. In addition, supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma and southwestern Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of approximately 1.2 million barrels and (4) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and at throughput terminals on Magellan s refined products distribution systems. In addition to rack sales (sales which are made at terminals into third-party tanker trucks), we make bulk sales (sales through third-party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise and NuStar. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States. Cushing is supplied by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude variety in the world capable of being transported by pipeline.

Throughput (the volume processed at a facility) at the refinery has markedly increased since July 2005. Management s focus on crude slate optimization (the process of determining the most economic crude oils to be refined), reliability, technical support and operational excellence coupled with prudent expenditures on equipment has significantly improved the operating metrics of the refinery. Historically, the refinery operated at an average crude throughput rate of less than 90,000 bpd. The plant averaged over 102,000 bpd of crude throughput in the second quarter of 2006, over

94,500 bpd for all 2006 and over 110,000 in the fourth quarter of 2007 with maximum daily rates in excess of

120,000 bpd for the fourth quarter of 2007. Not only were rates increased but yields were simultaneously improved. Since June 2005, the refinery has eclipsed monthly record (30-day) processing rates on approximately 70% of the individual units on site.

Crude is supplied to our refinery through our owned and leased gathering system and by a Plains pipeline from Cushing, Oklahoma. We maintain capacity on the Spearhead Pipeline from Canada and receive foreign and deepwater domestic crudes via the Seaway Pipeline system. We have also committed to additional pipeline capacity on the proposed Keystone pipeline project currently under development. We also maintain leased storage in Cushing to facilitate optimal crude purchasing and blending. We have significantly expanded the variety of crude grades processed in any given month from a limited few to over a dozen, including onshore and offshore domestic grades, various Canadian sours, heavy sours and sweet synthetics, and a variety of South American and West African imported grades. As a result of the crude slate optimization, we have improved the crude consumed cost discount to WTI from \$3.45 per barrel in 2005 to \$4.57 per barrel in 2006, \$5.04 per barrel in 2007 and \$5.31 per barrel in the first quarter of 2008.

Nitrogen Fertilizer Business. The nitrogen fertilizer segment consists of our interest in CVR Partners, LP, a limited partnership controlled by our affiliates. The nitrogen fertilizer business consists of a nitrogen fertilizer manufacturing facility, including (1) a 1,225 ton-per-day ammonia unit, (2) a 2,025 ton-per-day UAN unit and (3) an 84 million standard cubic foot per day gasifier complex, which consumes approximately 1,500 tons per day of pet coke to produce hydrogen. In 2007, the nitrogen fertilizer business produced approximately 326,662 tons of ammonia, of which approximately 72% was upgraded into approximately 576,888 tons of UAN. At current natural gas and pet coke prices, the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN fertilizers in North America. The nitrogen fertilizer business generated net sales of \$173.0 million, \$162.5 million and \$165.9 million, and operating income of \$71.0 million, \$36.8 million and \$46.6 million, for the years ended December 31, 2005, 2006 and 2007, respectively. The nitrogen fertilizer business generated net sales of \$62.6 million and operating income of \$26.0 million for the three months ended March 31, 2008.

The nitrogen fertilizer plant in Coffeyville, Kansas includes a pet coke gasifier that produces high purity hydrogen which in turn is converted to ammonia at a related ammonia synthesis plant. Ammonia is further upgraded into UAN solution in a related UAN unit. Pet coke is a low value by-product of the refinery coking process. On average during the last four years, more than 75% of the pet coke consumed by the nitrogen fertilizer plant was produced by our refinery. The nitrogen fertilizer business obtains most of its pet coke via a long-term coke supply agreement with us. As such, the nitrogen fertilizer business benefits from high natural gas prices, as fertilizer prices generally increase with natural gas prices, without a directly related change in cost (because pet coke is used as a primary raw material rather than natural gas).

The nitrogen fertilizer plant is the only commercial facility in North America utilizing a pet coke gasification process to produce nitrogen fertilizers. The use of low cost by-product pet coke from the adjacent oil refinery (rather than natural gas) to produce hydrogen provides the facility with a significant competitive advantage given the currently high and volatile natural gas prices. The nitrogen fertilizer business competition utilizes natural gas to produce ammonia. Historically, pet coke has been a less expensive feedstock than natural gas on a per-ton of fertilizer produced basis.

Capital Projects. Management has identified, developed and substantially completed several significant capital projects since June 2005 with a total cost of approximately \$522 million (including \$170 million in expenditures for our refinery expansion project, excluding \$3.7 million in related capitalized interest). Major projects include construction of a new diesel hydrotreater, a new continuous catalytic reformer, a new sulfur recovery unit, a new plant-wide flare system, a technology upgrade to the fluid catalytic cracking unit and a refinery-wide capacity expansion. Once completed, these projects are intended to significantly enhance the profitability of the refinery in environments of

Table of Contents

high crack spreads and allow the refinery to operate more profitably at lower crack spreads than is currently possible.

The spare gasifier at the nitrogen fertilizer plant was expanded in 2006, increasing ammonia production by 6,500 tons per year. In addition, the nitrogen fertilizer plant is moving forward with an approximately $120 million fertilizer plant expansion, of which approximately $11 million was incurred as of March 31, 2008. We estimate this expansion will increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium-priced UAN by approximately 50%. Management currently expects to complete this expansion in July 2010. This project is also expected to improve the nitrogen fertilizer business cost structure by eliminating the need for rail shipments of ammonia, thereby reducing the risks associated with such rail shipments and avoiding anticipated cost increases in such transport.

Recent Developments

During the second quarter of 2008, we are enjoying unprecedented fertilizer prices which have contributed favorably to our earnings. Strong industry fundamentals have led current demand for nitrogen fertilizers to all time highs. U.S. corn inventories at the end of the 2008-2009 fertilizer year are projected to be at 673 million bushels, which is the lowest level since 1995-1996. Corn prices are at record high levels, and corn planting for 2008-2009 is projected to be higher than 2007-2008. Nitrogen fertilizer prices are at record high levels due to increased demand and increasing worldwide natural gas prices. In addition, nitrogen fertilizer prices, which historically showed a positive correlation with natural gas prices, have been decoupled from, and increased substantially more than, natural gas prices in 2007 and 2008. In addition to demand driven by biofuel fuel production, the quest for healthier lives and better diets in developing countries is a primary driving factor behind the increased global demand for fertilizers. As of June 16, 2008, our order book for UAN included 367,825 tons at an average netback price of $326.56 per ton and 34,898 tons of ammonia at an average netback price of $620.61 per ton.

At the same time, however, crude oil prices have reached record levels, and while crack spreads have increased to historically high absolute values, they are below historical levels as a percentage of crude oil prices. Because crack spreads as a percentage of crude oil prices have not kept pace with increasing crude oil prices, our earnings will be negatively impacted in the second quarter of 2008. The Cash Flow Swap will also have a material negative impact on our earnings through at least June 2009 due to the fact that losses on the Cash Flow Swap increase as crack spreads in absolute terms increase. In addition, our second quarter has been negatively impacted by unplanned downtime at the fertilizer plant and the refinery and increase in non-cash share-based compensation costs as a result of our increased stock price.

We have begun negotiations to enter into a new $25.0 million senior secured term loan, or the proposed senior secured credit facility, which we anticipate will contain covenants substantially similar to our existing credit facility. We have not entered into any agreement regarding this new credit facility, and there is no guarantee that we will be able to enter into the proposed senior secured credit facility on the terms described herein or at all.

Restatement of Year Ended December 31, 2007 and Quarter Ended September 30, 2007 Financial Statements

On April 23, 2008, the audit committee of our board of directors and management concluded that our previously issued consolidated financial statements for the year ended December 31, 2007 and the related quarter ended September 30, 2007 contained errors. We arrived at this conclusion during the course of our closing process and review for the quarter ended March 31, 2008. As a result of these errors, management concluded that our internal control over financial reporting was not adequate to determine the cost of crude oil at period end. Specifically, the Company s policies and procedures for estimating the cost of crude oil and reconciling these estimates to vendor invoices

79

were not effective. Additionally, the Company s supervision and review of this estimation and reconciliation process was not operating at a level of detail adequate to identify the deficiencies in the process. Management concluded that these deficiencies were material weaknesses in our internal control over financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company s annual or interim financial statements will not be prevented or detected on a timely basis. Due to these material weaknesses, our management also concluded that we did not maintain effective disclosure controls and procedures as of December 31, 2007.

Our restated financial results were filed with the SEC with a Form 10-K/A on May 8, 2008. See footnote 2 to our consolidated financial statements for the year ended December 31, 2007 included elsewhere in this prospectus. All information presented in this prospectus reflects our restated financial results.

In order to remediate the material weaknesses described above, our management is in the process of designing, implementing and enhancing controls to ensure the proper accounting for the calculation of the cost of crude oil. These remedial actions include, among other things, (1) centralizing all crude oil cost accounting functions, (2) adding additional layers of accounting review with respect to our crude oil cost accounting and (3) adding additional layers of business review with respect to the computation of our crude oil costs.

All of the information presented in this prospectus reflects our restated financial results.

CVR Energy s Initial Public Offering

On October 26, 2007, we completed an initial public offering of 23,000,000 shares of our common stock. The initial public offering price was $19.00 per share. The net proceeds to us from the sale of our common stock were approximately $408.5 million, after deducting underwriting discounts and commissions, but before deduction of offering expenses. We also incurred approximately $11.4 million of other costs related to the initial public offering.

The net proceeds from the offering were used to repay $280.0 million of our outstanding term loan debt and to repay in full our $25.0 million secured credit facility and $25.0 million unsecured credit facility. We also repaid $50.0 million of indebtedness under our revolving credit facility.

In connection with the initial public offering, we also became the indirect owner of Coffeyville Resources, LLC and all of its refinery assets. This was accomplished by the issuance of 62,866,720 shares of our common stock to certain entities controlled by our majority stockholders pursuant to a stock split in exchange for the interests in certain subsidiaries of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, excluding any restricted shares issued.

Major Influences on Results of Operations

Petroleum Business

Our earnings and cash flows from our petroleum operations are primarily affected by the relationship between refined product prices and the prices for crude oil and other feedstocks. Feedstocks are petroleum products, such as crude oil and natural gas liquids, that are processed and blended into refined products. The cost to acquire feedstocks and the price for which refined products are ultimately sold depend on factors beyond our control, including the supply of, and demand for, crude oil, as well as gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation.

Because we apply first-in, first-out, or FIFO, accounting to value our inventory, crude oil price movements may impact net income in the short term because of instantaneous changes in the value of the minimally required, unhedged on hand inventory. The effect of changes in crude oil prices on our results of operations is influenced by the rate at which the prices of refined products adjust to reflect these changes.

Feedstock and refined product prices are also affected by other factors, such as product pipeline capacity, local market conditions and the operating levels of competing refineries. Crude oil costs and the prices of refined products have historically been subject to wide fluctuations. An expansion or upgrade of our competitors facilities, price volatility, international political and economic developments and other factors beyond our control are likely to continue to play an important role in refining industry economics. These factors can impact, among other things, the level of inventories in the market, resulting in price volatility and a reduction in product margins. Moreover, the refining industry typically experiences seasonal fluctuations in demand for refined products, such as increases in the demand for gasoline during the summer driving season and for home heating oil during the winter, primarily in the Northeast.

Crude oil costs are at historic highs. West Texas Intermediate crude oil averaged $97.82 per barrel for the three months ended March 31, 2008, as compared to $58.27 per barrel during the comparable period in 2007. WTI crude oil prices averaged over $105 per barrel in March 2008 and had spiked to over $138.75 per barrel as of June 6, 2008. There are a number of reasons why high crude oil costs and current crack spreads have a negative impact on our business. First, as crack spreads increase in absolute terms in connection with higher crude oil prices, we realize increasing losses on the Cash Flow Swap. We expect the Cash Flow Swap will continue to have a material negative effect on our earnings at least through June 2009. Second, every barrel of crude oil that we process yields approximately 88% high performance transportation fuels and approximately 12% less valuable byproducts such as pet coke, slurry and sulfur and volumetric losses (lost volume resulting from the change from liquid form to solid). Whereas crude oil costs have increased, sales prices for many byproducts have not increased in the same proportions. As a result, we lose money on byproduct sales (and from the inherent lost volume in shifting from liquid to solid form), resulting in a reduction to our earnings.

In order to assess our operating performance, we compare our net sales, less cost of product sold (refining margin), against an industry refining margin benchmark. The industry refining margin is calculated by assuming that two barrels of benchmark light sweet crude oil is converted into one barrel of conventional gasoline and one barrel of distillate. This benchmark is referred to as the 2-1-1 crack spread. Because we calculate the benchmark margin using the market value of New York Mercantile Exchange (NYMEX) gasoline and heating oil against the market value of NYMEX WTI (WTI) crude oil, we refer to the benchmark as the NYMEX 2-1-1 crack spread, or simply, the 2-1-1 crack spread. The 2-1-1 crack spread is expressed in dollars per barrel and is a proxy for the per barrel margin that a sweet crude refinery would earn assuming it produced and sold the benchmark production of gasoline and heating oil. The 2-1-1 crack spreads were significantly narrower in the first quarter of 2008 as a percentage of crude oil prices when compared to the first quarter of 2007. As a percentage of crude oil prices, the 2-1-1 crack spread was approximately 21% in the first quarter of 2007 but only 12% in the first quarter of 2008.

Although the 2-1-1 crack spread is a benchmark for our refinery margin, because our refinery has certain feedstock costs and/or logistical advantages as compared to a benchmark refinery and our product yield is less than total refinery throughput, the crack spread does not account for all the factors that affect refinery margin. Our refinery is able to process a blend of crude oil that includes quantities of heavy and medium-sour crude oil that has historically cost less than WTI crude oil. We measure the cost advantage of our crude oil slate by calculating the spread between the price of our delivered crude oil to the price of WTI crude oil, a light sweet crude oil. The spread is referred to as our consumed crude differential. Our refinery margin can be impacted significantly by the consumed crude differential. Our consumed crude differential will move directionally with changes in the West Texas Sour (WTS) differential to WTI and the West Canadian Select (WCS) differential to WTI as both

these differentials indicate the relative price of heavier, more sour, slate to WTI. The WCS-WTI differential for the first quarter of 2008 was $19.84 a barrel as compared to $14.80 a barrel in the first quarter of 2007. The differential for the fourth quarter of 2007 was $32.60 a barrel. The correlation between our consumed crude differential and published differentials will vary depending on the volume of light medium-sour crude and heavy sour crude we purchase as a percent of our total crude volume and will correlate more closely with such published differentials the heavier and more sour the crude oil slate.

We produce a high volume of high value products, such as gasoline and distillates. Approximately 39% of our product slate is ultra low sulfur diesel, which provides us with tax credits and is currently selling at higher margins than gasoline (which represents 48% of our refined products). The balance of our production is devoted to other products, including the petroleum coke used by the nitrogen fertilizer business. We benefit from the fact that our marketing region consumes more refined products than it produces so that the market prices of our products have to be high enough to cover the logistics cost for the U.S. Gulf Coast refineries to ship into our region. The result of this logistical advantage and the fact the actual product specification used to determine the NYMEX is different from the actual production in the refinery is that prices we realize are different than those used in determining the 2-1-1 crack spread. The difference between our price and the price used to calculate the 2-1-1 crack spread is referred to as gasoline PADD II, Group 3 vs. NYMEX basis, or gasoline basis, and heating oil PADD II, Group 3 vs. NYMEX basis, or heating oil basis.

Our direct operating expense structure is also important to our profitability. Major direct operating expenses include energy, employee labor, maintenance, contract labor, and environmental compliance. Our predominant variable cost is energy which is comprised primarily of electrical cost and natural gas. We are therefore sensitive to the movements of natural gas prices.

Consistent, safe, and reliable operations at our refinery are key to our financial performance and results of operations. Unplanned downtime at our refinery may result in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position. We seek to mitigate the financial impact of planned downtime, such as major turnaround maintenance, through a diligent planning process that takes into account the margin environment, the availability of resources to perform needed maintenance, feedstocks and other factors.

We purchase most of our crude oil using a credit intermediation agreement. Our credit intermediation agreement is structured such that we take title, and the price of the crude oil is set, when it is metered and delivered at Broome Station, which is connected to, and located approximately 22 miles from, our refinery. Once delivered at Broome Station, the crude oil is delivered to our refinery through two of our wholly owned pipelines which begin at Broome Station and end at our refinery. The crude oil is delivered at Broome Station because Broome Station is located near our facility and is connected via pipeline to our facility. The terms of the credit intermediation agreement provide that we will obtain all of the crude oil for our refinery, other than the crude we obtain through our own gathering system, through J. Aron. Once we identify cargos of crude oil and pricing terms that meet our requirements, we notify J. Aron and J. Aron then provides credit, transportation and other logistical services to us for a fee. This agreement significantly reduces the investment that we are required to maintain in petroleum inventories relative to our competitors and reduces the time we are exposed to market fluctuations before the inventory is priced to a customer.

Because petroleum feedstocks and products are essentially commodities, we have no control over the changing market. Therefore, the lower target inventory we are able to maintain significantly reduces the impact of commodity price volatility on our petroleum product inventory position relative to other refiners. This target inventory position is generally not hedged. To the extent our inventory position deviates from the target level, we consider risk mitigation activities usually through the purchase or sale of futures contracts on the New York Mercantile Exchange, or NYMEX. Our hedging activities carry customary time, location and product grade basis risks generally associated with

hedging activities. Because most of our titled inventory is valued under the FIFO costing method, price fluctuations on our target level of titled inventory have a major effect on our financial results unless the market value of our target inventory is increased above cost.

Nitrogen Fertilizer Business

In the nitrogen fertilizer business, earnings and cash flow from operations are primarily affected by the relationship between nitrogen fertilizer product prices and direct operating expenses. Unlike its competitors, the nitrogen fertilizer business uses minimal natural gas as feedstock and, as a result, is not directly impacted in terms of cost by high or volatile swings in natural gas prices. Instead, our adjacent oil refinery supplies most of the pet coke feedstock needed by the nitrogen fertilizer business pursuant to a long-term pet coke supply agreement. The price at which nitrogen fertilizer products are ultimately sold depends on numerous factors, including the supply of, and the demand for, nitrogen fertilizer products which, in turn, depends on, among other factors, the price of natural gas, the cost and availability of fertilizer transportation infrastructure, changes in the world population, weather conditions, grain production levels, the availability of imports, and the extent of government intervention in agriculture markets. While net sales of the nitrogen fertilizer business could fluctuate significantly with movements in natural gas prices during periods when fertilizer markets are weak and nitrogen fertilizer products sell at low prices, high natural gas prices do not force the nitrogen fertilizer business to shut down its operations because it employs pet coke as a feedstock to produce ammonia and UAN rather than natural gas.

Nitrogen fertilizer prices are also affected by other factors, such as local market conditions and the operating levels of competing facilities. Natural gas costs and the price of nitrogen fertilizer products have historically been subject to wide fluctuations. An expansion or upgrade of competitors facilities, price volatility, international political and economic developments and other factors are likely to continue to play an important role in nitrogen fertilizer industry economics. These factors can impact, among other things, the level of inventories in the market, resulting in price volatility and a reduction in product margins. Moreover, the industry typically experiences seasonal fluctuations in demand for nitrogen fertilizer products.

The demand for fertilizers is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers. Individual farmers make planting decisions based largely on the prospective profitability of a harvest, while the specific varieties and amounts of fertilizer they apply depend on factors like crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted.

The value of nitrogen fertilizer products is also an important consideration in understanding our results. The nitrogen fertilizer business generally upgrades approximately two-thirds of its ammonia production into UAN, a product that presently generates a greater value than ammonia. UAN production is a major contributor to our profitability. In order to assess the value of nitrogen fertilizer products, we calculate netbacks, also referred to as plant gate price. Netbacks refer to the unit price of fertilizer, in dollars per ton, offered on a delivered basis, excluding shipment costs.

Prices for both ammonia and UAN for the quarter ended March 31, 2008 reflect strong current demand for these products. Ammonia plant gate prices averaged $494 per ton for the quarter ended March 31, 2008, compared to $347 per ton during the comparable period in 2007. UAN prices averaged $262 per ton for the quarter ended March 31, 2008, compared to $169 per ton during the comparable 2007 period. The prices for both ammonia and UAN continue to rise. Our order book as of June 16, 2008 contains average netback prices for ammonia and UAN of $327 and $621 per ton, respectively.

The direct operating expense structure of the nitrogen fertilizer business is also important to its profitability. Using a pet coke gasification process, the nitrogen fertilizer business has significantly higher fixed costs than natural gas-based fertilizer plants. Major direct operating expenses include

83

electrical energy, employee labor, maintenance, including contract labor, and outside services. These costs comprise the fixed costs associated with the fertilizer plant.

Variable costs associated with the nitrogen fertilizer plant have averaged approximately 1.2% of direct operating expenses over the last 24 months ended December 31, 2007. The average annual operating costs over the 24 months ended December 31, 2007 have approximated $65 million, of which substantially all are fixed in nature.

The nitrogen fertilizer business largest raw material expense is pet coke, which it purchases from us and third parties. In 2007, the nitrogen fertilizer business spent $13.6 million for pet coke. If pet coke prices rise substantially in the future, the nitrogen fertilizer business may be unable to increase its prices to recover increased raw material costs, because market prices for nitrogen fertilizer products are generally correlated with natural gas prices, the primary raw material used by its competitors, and not pet coke prices.

The nitrogen fertilizer business generally undergoes a facility turnaround every two years. The turnaround typically lasts 15-20 days each turnaround year and requires approximately $2-3 million in direct costs per turnaround. The next facility turnaround is currently scheduled for the fourth quarter of 2008.

Agreements Between CVR Energy and the Partnership

In connection with our initial public offering and the transfer of the nitrogen fertilizer business to the Partnership in October 2007, we entered into a number of agreements with the Partnership that govern the business relations between the parties. These include the coke supply agreement, under which we sell pet coke to the nitrogen fertilizer business; a services agreement, in which our management operates the nitrogen fertilizer business; a feedstock and shared services agreement, which governs the provision of feedstocks, including hydrogen, high-pressure steam, nitrogen, instrument air, oxygen and natural gas; an omnibus agreement, which governs the division of future business opportunities between the two businesses; a raw water and facilities sharing agreement, which allocates raw water resources between the two businesses; an easement agreement; an environmental agreement; and a lease agreement pursuant to which we lease office space, storage and laboratory space to the Partnership.

The price paid by the nitrogen fertilizer business pursuant to the coke supply agreement is based on the lesser of a coke price derived from the price received by the Partnership for UAN (subject to a UAN based price ceiling and floor) and a coke price index for pet coke. For periods prior to our initial public offering and the transfer of the nitrogen fertilizer business to the Partnership, the cost of product sold (exclusive of depreciation and amortization) in the nitrogen fertilizer business on our financial statements was based on a coke price of $15 per ton beginning in March 2004. This is reflected in the segment data in our historical financial statements as a cost for the nitrogen fertilizer business and as revenue for the petroleum business. If the terms of the coke supply agreement had been in place over each of the past three years, the coke supply agreement would have resulted in an increase (or decrease) in cost of product sold (exclusive of depreciation and amortization) for the nitrogen fertilizer business (and an increase (or decrease) in revenue for the petroleum business) of $(1.6) million, $(0.7) million, $(3.5) million and $2.5 million for the 174-day period ended June 24, 2005, the 233-day period ended December 31, 2005, the year ended December 31, 2006 and the year ended December 31, 2007. There would have been no impact to the consolidated financial statements as intercompany transactions are eliminated upon consolidation.

In addition, based on management s current estimates, the services agreement will result in an annual charge of approximately $11.5 million (excluding share based compensation) to the nitrogen fertilizer business for its portion of expenses which have been historically reflected in selling, general and administrative expenses (exclusive of depreciation and amortization) in our consolidated statement of operations. Historical nitrogen fertilizer segment operating income would increase $0.8 million, decrease $0.1 million, increase $7.4 million and increase $8.9 million for the 174-day period ended

June 23, 2005, the 233-day period ended December 31, 2005, the year ended December 31, 2006 and the year ended December 31, 2007, respectively, assuming an annualized $11.5 million charge for the management services in lieu of the historical allocations of selling, general and administrative expenses. The petroleum segment s operating income would have had offsetting increases or decreases, as applicable, for these periods.

The total change to operating income for the nitrogen fertilizer segment as a result of both the 20-year coke supply agreement (which affects cost of product sold (exclusive of depreciation and amortization)) and the services agreement (which affects selling, general and administrative expense (exclusive of depreciation and amortization)), if both agreements had been in effect over the last three years, would be an increase of $2.4 million, an increase of $0.6 million, an increase of $10.9 million and an increase of $6.4 million for the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005, the year ended December 31, 2006 and the year ended December 31, 2007, respectively.

The feedstock and shared services agreement, the raw water and facilities sharing agreement, the cross-easement agreement and the environmental agreement are not expected to have a significant impact on the financial results of the nitrogen fertilizer business. However, the feedstock and shared services agreement includes provisions which require the nitrogen fertilizer business to provide hydrogen to us on a going-forward basis, as the nitrogen fertilizer business has done in recent years. This will have the effect of limiting the nitrogen fertilizer business fertilizer production, because the nitrogen fertilizer business will not be able to convert this hydrogen into ammonia. We believe that the addition of our new catalytic reformer will reduce, to some extent, but not eliminate, the amount of hydrogen the nitrogen fertilizer business will need to deliver to us, and we expect the nitrogen fertilizer business to continue to deliver hydrogen to us. The feedstock and shared services agreement requires us to compensate the nitrogen fertilizer business for the value of production lost due to the hydrogen supply requirement. See The Nitrogen Fertilizer Limited Partnership Intercompany Agreements .

Factors Affecting Comparability of Our Financial Results

Our results over the past three years have been, and our future periods will be, influenced by the following factors, which are fundamental to understanding comparisons of our period-to-period financial performance.

2007 Flood and Crude Oil Discharge

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville, Kansas. Our refinery and nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required extensive repairs. Total gross costs incurred and recorded as of March 31, 2008 related to the third party costs to repair the refinery and fertilizer facilities were approximately $82.5 million and $4.0 million, respectively. Additionally, other corporate overhead and miscellaneous costs incurred and recorded in connection with the flood as of March 31, 2008 were approximately $19.3 million. We currently estimate that approximately $2.1 million in third party costs related to the repair of flood damaged property will be recorded in future periods. In addition to the cost of repairing the facilities, we experienced a significant revenue loss attributable to the property damage during the period when the facilities were not in operation.

Despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. We have substantially completed remediation of the contamination caused by the crude oil discharge and expect any remaining minor remedial actions to be completed by December 31, 2008. Total net costs recorded as of March 31, 2008 associated with remediation efforts and third party property

85

damage incurred by the crude oil discharge are approximately $27.3 million. This amount is net of anticipated insurance recoveries of $21.4 million.

As of March 31, 2008, we have recorded total gross costs associated with the repair of, and other matters relating to the damage to our facilities and with third party and property damage remediation incurred due to the crude oil discharge of approximately $154.5 million. Total anticipated insurance recoveries of approximately $107.2 million have been recorded as March 31, 2008 (of which $21.5 million has already been received from insurance carriers by us), resulting in a net cost of approximately $47.3 million. We have not estimated any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from lawsuits related to the flood.

Refinancing and Prior Indebtedness

Effective May 10, 2004, Immediate Predecessor entered into a term loan of $150.0 million and a $75.0 million revolving loan facility with a syndicate of banks, financial institutions, and institutional lenders. Both loans were secured by substantially all of Immediate Predecessor s real and personal property, including receivables, contract rights, general intangibles, inventories, equipment, and financial assets. The covenants contained under the new term loan contained restrictions which limited the ability to pay dividends at the complete discretion of our board of directors. The Immediate Predecessor had no other restrictions on its ability to make dividend payments. Once any debt requirements were met, any dividends were at the discretion of our board of directors. There were outstanding borrowings of $148.9 million under the term loan and less than $0.1 million under the revolving loan facility at December 31, 2004. Outstanding borrowings on June 23, 2005 were repaid in connection with the Subsequent Acquisition.

Effective June 24, 2005, Coffeyville Resources, LLC entered into a first lien credit facility and a second lien credit facility. The first lien credit facility was in an aggregate amount not to exceed $525.0 million, consisting of $225.0 million tranche B term loans; $50.0 million of delayed draw term loans available for the first 18 months of the agreement and subject to accelerated payment terms; a $100.0 million revolving loan facility; and a funded letter of credit facility (funded facility) of $150.0 million for the benefit of the Cash Flow Swap provider. The first lien credit facility was secured by substantially all of Coffeyville Resources, LLC s assets. In June 2006 the first lien credit facility was amended and restated and the $225.0 million of tranche B term loans were refinanced with $225.0 million of tranche C term loans. The second lien credit facility was a $275.0 million term loan facility secured by substantially all of Coffeyville Resources, LLC s assets on a second priority basis.

On December 28, 2006, Coffeyville Resources, LLC entered into a new credit facility and used the proceeds thereof to repay its then existing first lien credit facility and second lien credit facility, and to pay a dividend to the members of Coffeyville Acquisition LLC. The credit facility provides financing of up to $1.075 billion, consisting of $775.0 million of tranche D term loans, a $150.0 million revolving credit facility, and a funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. The credit facility is secured by substantially all of Coffeyville Resources, LLC s assets. See Description of Our Indebtedness and the Cash Flow Swap. As a result, interest expense for the year ended December 31, 2007 was significantly higher than interest expense for the year ended December 31, 2006. Consolidated interest expense for the year ended December 31, 2007 was $61.1 million as compared to interest expense of $43.9 million for the year ended December 31, 2006. At December 31, 2006, we had a balance of $775.0 million on our term loan facility.

The 2007 flood and crude oil discharge had a significant negative effect on our liquidity in July/August 2007. As a result, in August 2007, our subsidiaries entered into a $25.0 million secured facility, a $25.0 million unsecured facility and a $75.0 million unsecured facility. Our statement of operations for the year ended December 31, 2007 includes $0.9 million in interest expense related to these facilities with no comparable amount for the same period in the prior year.

In October 2007, we paid down $280.0 million of outstanding long-term debt with initial public offering proceeds. In addition, proceeds of our initial public offering were used to repay in full our $25.0 million secured credit facility, our $25.0 million unsecured credit facility and $50.0 million of indebtedness under our revolving credit facility. No amounts were drawn under the $75.0 million unsecured facility, and it terminated upon consummation of our initial public offering.

Our statements of operations for the three months ended March 31, 2008 includes interest expense of $11.3 million on the term debt of $488.0 million. Interest expense associated with the term debt for the three months ended March 31, 2007 totaled $11.9 million. Term debt as of March 31, 2007 totaled $775.0 million.

J. Aron Deferrals

As a result of the flood and the temporary cessation of our operations on June 30, 2007, Coffeyville Resources, LLC entered into several deferral agreements with J. Aron with respect to the Cash Flow Swap, which is a series of commodity derivative arrangements whereby if crack spreads in absolute terms fall below a fixed level, J. Aron agreed to pay the difference to us, and if crack spreads in absolute terms rise above a fixed level, we agreed to pay the difference to J. Aron. These deferral agreements deferred to August 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. We are required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts, but as of March 31, 2008, we were not required to prepay any portion of the deferred amount.

Change in Reporting Entity as a Result of the Initial Public Offering

Prior to our initial public offering in October 2007, our operations were conducted by an operating partnership, Coffeyville Resources, LLC. The reporting entity of the organization was also a partnership. Immediately prior to the closing of our initial public offering, Coffeyville Resources, LLC became an indirect, wholly-owned subsidiary of CVR Energy. As a result, for periods ending after October 2007, we report our results of operations and financial condition as a corporation on a consolidated basis rather than as an operating partnership.

Public Company Expenses

We believe that our general and administrative expenses will increase due to the costs of operating as a public company, such as increases in legal, accounting and compliance, insurance premiums, and investor relations. We estimate that the increase in these costs will total approximately $2.5 million to $3.0 million on an annual basis, excluding the costs associated with the initial implementation of our Sarbanes-Oxley Section 404 internal controls review and testing. Our financial statements following the initial public offering reflect the impact of these expenses, whereas our financial statements for periods prior to the initial public offering do not reflect these expenses.

2007 Turnaround

In April 2007, we completed a planned turnaround of our refining plant at a total cost approximating $80.4 million, which included $66.0 million recorded in the first quarter of 2007. The refinery processed crude until February 11, 2007 at which time a staged shutdown of the refinery began. The refinery recommenced operations on March 22, 2007 and continually increased crude oil charge rates until all of the key units were restarted by April 23, 2007. The turnaround significantly impacted our financial results for 2007 and had no impact on our 2008 results.

2005 Acquisition

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. See Note 1 to our consolidated financial statements included elsewhere in this prospectus. We refer to this acquisition as the Subsequent Acquisition, and we refer to our post-June 24, 2005 operations as Successor. As a result of certain adjustments made in connection with this acquisition, a new basis of accounting was established on the date of the acquisition and the results of operations for the 233 days ended December 31, 2005 are not comparable to prior periods.

Cash Flow Swap

In connection with the Subsequent Acquisition in June 2005, Coffeyville Resources, LLC entered into a series of commodity derivative contracts, the Cash Flow Swap, in the form of three long-term swap agreements. Based on crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010, so long as at the time of reduction or termination, we pay the amount of unrealized losses associated with the amount reduced or terminated. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, in the financial statements for all periods after July 1, 2005, the statement of operations reflects all the realized and unrealized gains and losses from this swap. For the 233-day period ending December 31, 2005, we recorded realized and unrealized losses of $59.3 million and $235.9 million, respectively. For the year ending December 31, 2006, we recorded net realized losses of $46.8 million and net unrealized gains of $126.8 million. For the year ended December 31, 2007, we recorded net realized losses of $157.2 million and net unrealized losses of $103.2 million. The current environment of high and rising crude oil prices has led to higher crack spreads in absolute terms but significantly narrower crack spreads as a percentage of crude oil prices. As a result, the Cash Flow Swap, under which payments are calculated based on crack spreads in absolute terms has had and continues to have a material negative impact on our earnings. Due to the Cash Flow Swap, we estimate we will owe J. Aron approximately $54 million on July 8, 2008 for crude oil we settled or will settle with respect to the quarter ending June 30, 2008, based on June 16, 2008 pricing.

Property Tax Assessments

Our results of operations for the twelve months ending December 31, 2005 and 2006 reflect no property tax for our fertilizer facility (due to a tax abatement) and only a small property tax for our refinery. Our results of operations for the year ended December 31, 2007 reflect a substantially increased property tax for our refinery, and our results of operations for the three months ended March 31, 2008 reflect a substantially increased property tax for our fertilizer facility, as a result of new tax assessments by Montgomery County, Kansas and the end of the tax abatement. We have appealed both assessments. The refinery was again reappraised effective January 1, 2008. We have also appealed this new assessment, and believe that tax exemptions should apply to any incremental tax which would be owed as a result of the new assessment.

Consolidation of Nitrogen Fertilizer Limited Partnership

Prior to the consummation of our initial public offering, we transferred our nitrogen fertilizer business to the Partnership and sold the managing general partner interest in the Partnership to a new entity owned by our controlling stockholders and senior management. As of the date of this prospectus, we own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs) and are entitled to all cash that is distributed by the Partnership. The Partnership is operated by our senior management pursuant to a services agreement among us, the managing general partner and the Partnership. The Partnership is managed by the managing general partner and, to the extent described below, us, as special general partner. As special general partner of the Partnership, we have joint management rights regarding the appointment, termination and

Table of Contents

compensation of the chief executive officer and chief financial officer of the managing general partner, have the right to designate two members to the board of directors of the managing general partner and have joint management rights regarding specified major business decisions relating to the Partnership.

We consolidate the Partnership for financial reporting purposes. We have determined that following the sale of the managing general partner interest to an entity owned by our controlling stockholders and senior management, the Partnership is a variable interest entity (VIE) under the provisions of FASB Interpretation No. 46R *Consolidation of Variable Interest Entities* (FIN No. 46R).

Using criteria in FIN No. 46R, management has determined that we are the primary beneficiary of the Partnership, although 100% of the managing general partner interest is owned by a new entity owned by our controlling stockholders and senior management outside our reporting structure. Since we are the primary beneficiary, the financial statements of the Partnership remain consolidated in our financial statements. The managing general partner s interest is reflected as a minority interest on our balance sheet.

The conclusion that we are the primary beneficiary of the Partnership and required to consolidate the Partnership as a variable interest entity is based upon the fact that substantially all of the expected losses are absorbed by the special general partner, which we own. Additionally, substantially all of the equity investment at risk was contributed on behalf of the special general partner, with nominal amounts contributed by the managing general partner. The special general partner is also expected to receive the majority, if not substantially all, of the expected returns of the Partnership through the Partnership s cash distribution provisions.

We will need to reassess from time to time whether we remain the primary beneficiary of the Partnership in order to determine if consolidation of the Partnership remains appropriate on a going forward basis. Should we determine that we are no longer the primary beneficiary of the Partnership, we will be required to deconsolidate the Partnership in our financial statements for accounting purposes on a going-forward basis. In that event, we would be required to account for our investment in the Partnership under the equity method of accounting, which would affect our reported amounts of consolidated revenues, expenses and other income statement items.

The principal events that would require the reassessment of our accounting treatment related to our interest in the Partnership include:

- a sale of some or all of our partnership interests to an unrelated party;
- a sale of the managing general partner interest to a third party;
- the issuance by the Partnership of partnership interests to parties other than us or our related parties; and
- the acquisition by us of additional partnership interests (either new interests issued by the Partnership or interests acquired from unrelated interest holders).

In addition, we would need to reassess our consolidation of the Partnership if the Partnership s governing documents or contractual arrangements are changed in a manner that reallocates between us and other unrelated parties either (1) the obligation to absorb the expected losses of the Partnership or (2) the right to receive the expected residual returns of the Partnership.

Industry Factors

Petroleum Business

Earnings for our petroleum business depend largely on our refining margins, which have been and continue to be volatile. Crude oil and refined product prices depend on factors beyond our control.

Table of Contents

While it is impossible to predict refining margins due to the uncertainties associated with global crude oil supply and global and domestic demand for refined products, we believe that refining margins for U.S. refineries will generally remain above those experienced in the periods prior to 2003. Growth in demand for refined products in the United States, particularly transportation fuels, continues to exceed the ability of domestic refiners to increase capacity. In addition, changes in global supply and demand and other factors have affected the extent to which product importation to the United States can relieve domestic supply deficits. Our marketing region continues to be undersupplied and is a net importer of transportation fuels.

Crude oil discounts also contribute to our petroleum business earnings. Discounts for sour and heavy sour crude oils compared to sweet crudes continue to fluctuate widely. The worldwide production of sour and heavy sour crude oil, continuing demand for light sweet crude oil, and the increasing volumes of Canadian sours to the mid-continent continue to cause wide swings in discounts. As a result of our expansion project, we continue to increase volumes of heavy sour Canadian crudes and reduce our dependence on more expensive light sweet crudes.

Nitrogen Fertilizer Business

Global demand for fertilizers typically grows at predictable rates and tends to correspond to growth in grain production and pricing. Global fertilizer demand is driven in the long term primarily by population growth, increases in disposable income and associated improvements in diet. Short-term demand depends on world economic growth rates and factors creating temporary imbalances in supply and demand. We operate in a highly competitive, global industry. Our products are globally-traded commodities and, as a result, we compete principally on the basis of delivered price. We are geographically advantaged to supply nitrogen fertilizer products to the Corn Belt compared to U.S. Gulf Coast producers and our gasification process requires approximately 1% of the natural gas relative to natural gas-based fertilizer producers.

Currently, the nitrogen fertilizer market is driven by an almost unprecedented increase in demand. According to the United States Department of Agriculture (USDA), U.S. farmers planted 92.9 million acres of corn in 2007, exceeding the 2006 planted area by 19%. The actual planted acreage is the highest on record since 1944, when farmers planted 95.5 million acres of corn. The USDA is forecasting as of March 2008 that total U.S. planted corn acreage in 2008 will decline to 86 million acres. Despite this decrease, Blue Johnson estimates that nitrogen fertilizer consumption by farm users will increase by one million tons due to the need to correct for under fertilization of corn in 2007, a forecasted increase in total planted wheat acreage and very strong crop prices. This estimated increase in nitrogen usage translates into an annual increase of 3.3 million tons of UAN, or approximately five times our total 2008 estimated UAN production.

Total worldwide ammonia capacity has been growing. A large portion of the net growth has been in China and is attributable to China maintaining its self-sufficiency with regards to ammonia. Excluding China and the former Soviet Union, the trend in net ammonia capacity has been essentially flat since the late 1990s, as new plant construction has been offset by plant closures in countries with high-cost feedstocks. The high cost of capital is also limiting capacity increase. Today s strong market growth appears to be readily absorbing the latest capacity additions.

Earnings for the nitrogen fertilizer business depend largely on the prices of nitrogen fertilizer products, the floor price of which is directly influenced by natural gas prices. Natural gas prices have been and continue to be volatile. In addition, nitrogen fertilizer prices have been decoupled from their historical correlation with natural gas prices in recent years and increased substantially more than natural gas prices in 2007 and 2008 (based on data provided by Blue Johnson).

Table of Contents

Results of Operations

In this Results of Operations section, we first review our business on a consolidated basis, and then separately review the results of operations of each of our petroleum and nitrogen fertilizer businesses on a standalone basis.

Consolidated Results of Operations

The period-to-period comparisons of our results of operations have been prepared using the historical periods included in our financial statements. As discussed in Note 1 to our consolidated financial statements, effective June 24, 2005, Successor acquired the net assets of Immediate Predecessor in a business combination accounted for as a purchase. As a result of this acquisition, the consolidated financial statements for the periods after the acquisition are presented on a different cost basis than that for the period before the acquisition and, therefore, are not comparable. Accordingly, in this Results of Operations section, after comparing the three months ended March 31, 2008 with the three months ended March 31, 2007 and the year ended December 31, 2007 with the year ended December 31, 2006, we compare the year ended December 31, 2006 with the 174-day period ended June 23, 2005 and the 233-day period ended December 31, 2005.

Net sales consist principally of sales of refined fuel and nitrogen fertilizer products. For the petroleum business, net sales are mainly affected by crude oil and refined product prices, changes to the input mix and volume changes caused by operations. Product mix refers to the percentage of production represented by higher value light products, such as gasoline, rather than lower value finished products, such as pet coke. In the nitrogen fertilizer business, net sales are primarily impacted by manufactured tons and nitrogen fertilizer prices.

Industry-wide petroleum results are driven and measured by the relationship, or margin, between refined products and the prices for crude oil referred to as crack spreads. See Major Influences on Results of Operations. We discuss our results of petroleum operations in the context of per barrel consumed crack spreads and the relationship between net sales and cost of product sold.

Our consolidated results of operations include certain other unallocated corporate activities and the elimination of intercompany transactions and therefore are not a sum of only the operating results of the petroleum and nitrogen fertilizer businesses.

In order to effectively review and assess our historical financial information below, we have also included supplemental operating measures and industry measures which we believe are material to understanding our business. For the year ended December 31, 2005, we have provided this supplemental information on a combined basis in order to provide a comparative basis for similar periods of time. As discussed above, due to the acquisition that occurred, there were two financial statement periods in the 2005 calendar year of less than 12 months. We believe that the most meaningful way to present this supplemental data for the 2005 calendar year is to compare the sum of the combined operating results for the year ended December 31, 2005 with the year ended December 31, 2006. Accordingly, for purposes of displaying supplemental operating data for the year ended December 31, 2005, we have combined the 174-day period ended June 23, 2005 and the 233-day period ended December 31, 2005 to provide a comparative year ended December 31, 2005 to the year ended December 31, 2006.

We changed our method of allocating corporate selling, general and administrative expense to the operating segments in 2007. The effect of the change on operating income for 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005 and the year ended December 31, 2006 would have been a decrease of $1.0 million, $1.4 million and $6.0 million, respectively, to the petroleum segment, an increase of $1.2 million, $1.4 million and $6.0 million, respectively, to the nitrogen fertilizer segment and a decrease of $0.2 million, $0.0 million and $0.0 million, respectively, to the other segment.

Table of Contents

The following table provides an overview of our results of operations during the past three fiscal years and the three months ended March 31, 2007 and March 31, 2008:

Consolidated Financial Results	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
	(in millions)					
Net sales	$ 980.7	$ 1,454.3	$ 3,037.6	$ 2,966.9	$ 390.5	$ 1,223.0
Cost of product sold (exclusive of depreciation and amortization)	768.0	1,168.1	2,443.4	2,308.8	303.7	1,036.2
Direct operating expenses (exclusive of depreciation and amortization)	80.9	85.3	199.0	276.1	113.4	60.6
Selling, general and administrative expense (exclusive of depreciation and amortization)	18.4	18.4	62.6	93.1	13.2	13.4
Net costs associated with flood(1)				41.5		5.8
Depreciation and amortization(2)	1.1	24.0	51.0	60.8	14.2	19.6
Operating income	$ 112.3	$ 158.5	$ 281.6	$ 186.6	$ (54.0)	$ 87.4
Net income (loss)(3)	52.4	(119.2)	191.6	(67.6)	(154.4)	22.2
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	52.4	23.6	115.4	(5.6)	(137.0)	(47.9)

(1) Represents the write-off of approximate net costs associated with the flood and crude oil discharge that are not probable of recovery. See Flood and Crude Oil Discharge.

(2) Depreciation and amortization is comprised of the following components as excluded from cost of products sold, direct operating expense and selling, general and administrative expense:

Consolidated Financial Results	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Year Ended December 31, 2006	2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
	(in millions)					

Depreciation and amortization excluded from cost of product sold	$	0.1	$	1.1	$	2.2	$	2.4	$	0.6	$	0.6
Depreciation and amortization excluded from direct operating expenses		0.9		22.7		47.7		57.4		13.5		18.7
Depreciation and amortization excluded from selling, general and administrative expense		0.1		0.2		1.1		1.0		0.1		0.3
Depreciation included in net costs associated with flood								7.6				
Total depreciation and amortization	$	1.1	$	24.0	$	51.0	$	68.4	$	14.2	$	19.6

(3) The following are certain charges and costs incurred in each of the relevant periods that are meaningful to understanding our net income and in evaluating our performance due to their unusual or infrequent nature:

Consolidated Financial Results	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	Three Months Ended March 31, 2008 (unaudited)
	(in millions)					
Loss of extinguishment of debt(a)	$ 8.1	$	$ 23.4	$ 1.3	$	$
Inventory fair market value adjustment(b)		16.6				
Funded letter of credit expense & interest rate swap not included in interest expense(c)		2.3		1.8		0.9
Major scheduled turnaround expense(d)			6.6	76.4	66.0	
Loss on termination of swap(e)		25.0				
Unrealized (gain) loss from Cash Flow Swap		235.9	(126.8)	103.2	119.7	13.9

(a) Represents the write-off of $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005, the write-off of $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006 and the write-off of $1.3 million in connection with the repayment and termination of three credit facilities on October 26, 2007.

(b) Consists of the additional cost of product sold expense due to the step up to estimated fair value of certain inventories on hand at June 24, 2005, as a result of the allocation of the purchase price of the Subsequent Acquisition to inventory.

(c) Consists of fees which are expensed to selling, general and administrative expense in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. We consider these fees to be equivalent to interest expense and the fees are treated as such in the calculation of EBITDA in the credit facility.

(d) Represents expenses associated with a major scheduled turnaround at the nitrogen fertilizer plant and our refinery.

(e) Represents the expense associated with the expiration of the crude oil, heating oil and gasoline option agreements entered into by Coffeyville Acquisition LLC in May 2005.

(4) Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the unrealized portion of the derivative transaction that was executed in conjunction with the Subsequent Acquisition. On June 16, 2005, Coffeyville Acquisition LLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The

derivative took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not as a percentage of crude oil prices) crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. The Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010, so long as at the time of reduction or termination, we pay the amount of unrealized losses associated with the amount reduced or terminated.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements which is accounted for as a liability on our balance sheet. As the absolute crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our statement of operations. Conversely, as absolute crack spreads decline, we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (loss) adjusted for unrealized gain or loss from Cash Flow

Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our board of directors considers our GAAP net income results as well as Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our financial performance or liquidity but instead should be utilized as a supplemental measure of performance in evaluating our business. Because Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our cash flow swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

The following is a reconciliation of Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap to Net income (loss):

Consolidated Financial Results	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Successor Year Ended December 31, 2006	Successor Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	Three Months Ended March 31, 2008 (unaudited)
	(in millions)					
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap	$ 52.4	$ 23.6	$ 115.4	$ (5.6)	$ (82.4)	$ 30.6
Plus:						
Unrealized gain or (loss) from Cash Flow Swap, net of taxes		(142.8)	76.2	(62.0)	(72.0)	(8.4)
Net income (loss)	$ 52.4	$ (119.2)	$ 191.6	$ (67.6)	$ (154.4)	$ 22.2

Three Months Ended March 31, 2008 Compared to the Three Months Ended March 31, 2007 (Consolidated)

Net Sales. Consolidated net sales were $1,223.0 million for the three months ended March 31, 2008 compared to $390.5 million for the three months ended March 31, 2007. The increase of $832.5 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily due to an increase in petroleum net sales of $816.0 million that resulted from higher sales volumes ($592.1 million) primarily resulting from the refinery turnaround which began in February 2007 and was completed in April 2007 and higher product prices ($223.9 million). Nitrogen fertilizer net sales increased $24.0 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 primarily due to higher plant gate prices, partially offset by reductions in overall sales volume.

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $1,036.2 million for the three months ended March 31, 2008 as compared to $303.7 million for the three months ended March 31, 2007. The increase of $732.5 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 primarily resulted from a significant increase in refined fuel production volumes over the comparable period due to the refinery turnaround which began in February 2007 and was completed in April 2007.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $60.6 million for the three months ended March 31, 2008 as compared to $113.4 million for the three months ended March 31, 2007. This decrease of $52.8 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was due to a decrease in petroleum direct operating expenses of $56.4 million, primarily related to decreases in expenses associated with the refinery turnaround and labor, partially offset by increases in expenses associated with utilities and energy, repairs and maintenance, production chemicals, taxes and environmental. Nitrogen fertilizer direct operating expenses increased during the comparable period by $3.6 million, primarily due to increases in expenses associated with taxes, repairs and maintenance, labor, catalysts and outsides services, partially offset by decreases in expenses associated with utilities, royalties and other and equipment rental. The nitrogen fertilizer facility was subject to a property tax abatement which expired beginning in 2008. We have estimated our accrued property tax liability based upon the assessment value received by the county.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses were $13.4 million for the three months ended March 31, 2008 as compared to $13.2 million for the three months ended March 31, 2007. This variance was primarily the result of decreases in administrative labor ($3.0 million) primarily related to deferred compensation which was more than offset by increases in expenses related to outside services ($2.2 million), bad debt ($0.4 million), insurance ($0.3 million), bank charges ($0.2 million), public relations ($0.1 million) and other selling, general and administrative costs ($0.1 million).

Net Costs Associated with Flood. Consolidated net costs associated with flood for the three months ended March 31, 2008 approximated $5.8 million as compared to none for the three months ended March 31, 2007. As the flood occurred in the second and third quarter of 2007 there was no financial statement impact in the first quarter of 2007. Total gross costs recorded for the three months ended March 31, 2008 were approximately $7.6 million. Of these gross costs, approximately $3.8 million were associated with repair and other matters as a result of the damage to the Company s facilities. Included in this cost was $0.3 million of professional fees and $3.5 million for other repair and related costs. There were also approximately $3.8 million of costs recorded with respect to environmental remediation and property damage. Total accounts receivable from insurers approximated $85.7 million at March 31, 2008, for which we believe collection is probable.

Depreciation and Amortization. Consolidated depreciation and amortization was $19.6 million for the three months ended March 31, 2008 as compared to $14.2 million for the three months ended March 31, 2007. The increase in depreciation and amortization for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of the completion of several large capital projects.

Operating Income. Consolidated operating income was $87.4 million for the three months ended March 31, 2008 as compared to an operating loss of $54.0 million for the three months ended March 31, 2007. For the three months ended March 31, 2008 as compared to the three months ended March 31, 2007, petroleum operating income increased $127.1 million and nitrogen fertilizer operating income increased by $16.7 million.

Interest Expense. Consolidated interest expense for the three months ended March 31, 2008 was $11.3 million as compared to interest expense of $11.9 million for the three months ended March 31, 2007. This 5% decrease for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 primarily resulted from an overall decrease in the index rates (primarily LIBOR) and a decrease in average borrowings outstanding during the comparable periods.

Table of Contents

Interest Income. Interest income was $0.7 million for the three months ended March 31, 2008 as compared to $0.5 million for the three months ended March 31, 2007.

Loss on Derivatives, Net. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* For the three months ended March 31, 2008, we incurred $47.9 million in losses on derivatives. This compares to a $137.0 million loss on derivatives for the three months ended March 31, 2007. This significant decrease in loss on derivatives, net for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily attributable to the realized and unrealized losses on our Cash Flow Swap. Realized losses on the Cash Flow Swap for the three months ended March 31, 2008 and the three months ended March 31, 2007 were $21.5 million and $8.5 million, respectively. The increase in realized losses over the comparable periods was primarily the result of higher net barrels hedged for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007. Unrealized losses represent the change in the mark-to-market value on the unrealized portion of the Cash Flow Swap based on changes in the NYMEX crack spread that is the basis for the Cash Flow Swap. Unrealized losses on our Cash Flow Swap for the three months ended March 31, 2008 and the three months ended March 31, 2007 were $13.9 million and $119.7 million, respectively. This change in the unrealized loss of the Cash Flow Swap over the comparable periods reflect decreases in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In addition to the change in the NYMEX crack spread, the outstanding term of the Cash Flow Swap at the end of each period also affects the impact that the changes of the underlying crack spread may have on the unrealized gain or loss. As of March 31, 2008, the Cash Flow Swap had a remaining term of approximately two years and three months whereas as of March 31, 2007 the remaining term on the Cash Flow Swap was approximately three years and three months. As a result of the shorter remaining term as of March 31, 2008, a similar change in crack spread will have a smaller impact on the unrealized gains or losses.

Provision for Income Taxes. Income tax expense for the three months ended March 31, 2008 was $6.9 million, or 23.6% of income before income taxes, as compared to income tax benefit of $(47.3) million, or 23.4% of earnings before income taxes, for the three months ended March 31, 2007.

Minority Interest in (Income) Loss of Subsidiaries. Minority interest in loss of subsidiaries for the three months ended March 31, 2007 was $0.7 million compared to none during the three months ended March 31, 2008. Minority interest for 2007 related to common stock in two of our subsidiaries owned by our chief executive officer. In October 2007, in connection with our initial public offering, our chief executive officer exchanged his common stock in our subsidiaries for common stock of CVR Energy.

Net Income. For the three months ended March 31, 2008, net income increased to $22.2 million as compared to net loss of $(154.4) million for the three months ended March 31, 2007. Net income increased $176.6 million compared to the first quarter of 2007 primarily due to the planned turnaround that commenced in February 2007. For the three months ended March 31, 2007 the Company incurred costs of $66.0 million associated with the refinery turnaround. In addition the Company s net income was favorably impacted by a significant change in the fair value of the Cash Flow Swap over the comparable periods.

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006 (Consolidated).

Net Sales. Consolidated net sales were $2,966.9 million for the year ended December 31, 2007 compared to $3,037.6 million for the year ended December 31, 2006. The decrease of $70.7 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily due to a decrease in petroleum net sales of $74.2 million that resulted from lower

sales volumes ($576.9 million), partially offset by higher product prices ($502.7 million). Nitrogen fertilizer net sales increased $3.4 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 as reductions in overall sales volumes ($31.0 million) were more than offset by higher plant gate prices ($34.4 million). The sales volume decrease for the refinery primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood. The flood was also a major contributor to lower nitrogen fertilizer sales volume.

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $2,308.8 million for the year ended December 31, 2007 as compared to $2,443.4 million for the year ended December 31, 2006. The decrease of $134.6 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $276.1 million for the year ended December 31, 2007 as compared to $199.0 million for the year ended December 31, 2006. This increase of $77.1 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was due to an increase in petroleum direct operating expenses of $74.2 million, primarily related to the refinery turnaround, and an increase in nitrogen fertilizer direct operating expenses of $3.0 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses exclusive of depreciation and amortization were $93.1 million for the year ended December 31, 2007 as compared to $62.6 million for the year ended December 31, 2006. This variance was primarily the result of increases in administrative labor primarily related to deferred compensation and share-based compensation ($19.1 million), other costs primarily related to the termination of the management agreements with Goldman Sachs Funds and Kelso Funds ($10.6 million), bank charges ($1.3 million) and office costs ($0.3 million).

Net Costs Associated with Flood. Consolidated net costs associated with flood for the year ended December 31, 2007 approximated $41.5 million as compared to none for the year ended December 31, 2006. Total gross costs associated with the flood for the year ended December 31, 2007 were approximately $146.8 million. Of these gross costs, approximately $101.9 million were associated with repair and other matters as a result of the physical damage to the Company s facilities and approximately $44.9 million were associated with the environmental remediation and property damage. Included in the gross costs associated with the flood were certain costs that are excluded from the accounts receivable from insurers of $85.3 million at December 31, 2007, for which we believe collection is probable. The costs excluded from the accounts receivable from insurers were $7.6 million of depreciation for the temporarily idled facilities, $3.6 million of uninsured losses within the Company s insurance deductibles, $6.8 million of uninsured expenses and $23.5 million recorded with respect to environmental remediation and property damage. As of December 31, 2007, $20.0 million of insurance recoveries recorded in 2007 had been collected and are not reflected in the accounts receivable from insurers balance at December 31, 2007.

Depreciation and Amortization. Consolidated depreciation and amortization was $60.8 million for the year ended December 31, 2007 as compared to $51.0 million for the year ended December 31, 2006. During the restoration period for the refinery and our nitrogen fertilizer operations due to the flood, $7.6 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $7.6 million reclassification, the increase in consolidated depreciation and amortization for the year ended December 31, 2007 compared to the year ended December 31, 2006 would have been approximately $17.4 million. This adjusted increase in consolidated depreciation and

amortization for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of the completion of the several large capital projects in late 2006 and during the year ended December 31, 2007 in our Petroleum business.

Operating Income. Consolidated operating income was $186.6 million for the year ended December 31, 2007 as compared to operating income of $281.6 million for the year ended December 31, 2006. For the year ended December 31, 2007 as compared to the year ended December 31, 2006, petroleum operating income decreased $100.7 million primarily as a result of the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime associated with the flood. For the year ended December 31, 2007 as compared to the year ended December 31, 2006, nitrogen fertilizer operating income increased by $9.8 million as downtime and expenses associated with the flood and increases in direct operating expenses were more than offset by a reduction in cost of product sold and higher plant gate prices.

Interest Expense. Consolidated interest expense for the year ended December 31, 2007 was $61.1 million as compared to interest expense of $43.9 million for the year ended December 31, 2006. This 39% increase for the year ended December 31, 2007 as compared to the year ended December 31, 2006 primarily resulted from an overall increase in the index rates (primarily LIBOR) and an increase in average borrowings outstanding during the comparable periods. Partially offsetting these negative impacts on consolidated interest expense was a $0.4 million increase in capitalized interest over the comparable periods. Additionally, consolidated interest expense over the comparable periods was partially offset by decreases in the applicable margins under our credit facility dated December 28, 2006 as compared to our prior borrowing facility in effect for substantially all of the year ended December 31, 2006.

Interest Income. Interest income was $1.1 million for the year ended December 31, 2007 as compared to $3.5 million for the year ended December 31, 2006.

Gain (loss) on Derivatives. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* For the year ended December 31, 2007, we incurred $282.0 million in losses on derivatives. This compares to a $94.5 million gain on derivatives for the year ended December 31, 2006. This significant change in gain (loss) on derivatives for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily attributable to the realized and unrealized gains (losses) on our Cash Flow Swap. Realized losses on the Cash Flow Swap for the year ended December 31, 2007 and the year ended December 31, 2006 were $157.2 million and $46.8 million, respectively. The increase in realized losses over the comparable periods was primarily the result of higher average absolute crack spreads for the year ended December 31, 2007 as compared to the year ended December 31, 2006. Unrealized gains or losses represent the change in the mark-to-market value on the unrealized portion of the Cash Flow Swap based on changes in the NYMEX crack spread that is the basis for the Cash Flow Swap. Unrealized losses on our Cash Flow Swap for the year ended December 31, 2007 were $103.2 million and reflect an increase in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In contrast, the unrealized portion of the Cash Flow Swap for the year ended December 31, 2006 reported mark-to-market gains of $126.8 million and reflect a decrease in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In addition, the outstanding term of the Cash Flow Swap at the end of each period also affects the impact of changes in the underlying crack spread. As of December 31, 2007, the Cash Flow Swap had a remaining term of approximately two years and six months whereas as of December, 2006, the remaining term on the Cash Flow Swap was approximately three years and six months. As a result of the longer remaining term as of December 31, 2006, a similar change in crack spread will have a greater impact on the unrealized gains or losses.

Provision for Income Taxes. Income tax benefit for the year ended December 31, 2007 was $88.5 million, or 57% of loss before income taxes, as compared to income tax expense of

Table of Contents

$119.8 million, or 39% of earnings before income taxes, for the year ended December 31, 2006. Our effective tax rate increased in the year ended December 31, 2007 as compared to the year ended December 31, 2006 primarily due to the impact of the American Jobs Creation Act of 2004, which provides an income tax credit to small business refiners related to the production of ultra low sulfur diesel. We recognized an income tax benefit of approximately $17.3 million in 2007 compared to $4.5 million in 2006 on a credit of approximately $26.6 million in 2007 compared to a credit of approximately $6.9 million in 2006 related to the production of ultra low sulfur diesel. In addition, state income tax credits, net of federal expense, approximating $19.8 million were earned and recorded in 2007 that related to the expansion of the facilities in Kansas.

Minority Interest in (Income) Loss of Subsidiaries. Minority interest in loss of subsidiaries for the year ended December 31, 2007 was $0.2 million. Minority interest relates to common stock in two of our subsidiaries owned by our chief executive officer. In October 2007, in connection with our initial public offering, our chief executive officer exchanged his common stock in our subsidiaries for common stock of CVR Energy.

Net Income. For the year ended December 31, 2007, net income decreased to a net loss of $67.6 million as compared to net income of $191.6 million for the year ended December 31, 2006. Net income decreased $259.2 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006, primarily due to the refinery turnaround, downtime and costs associated with the flood and a significant change in the value of the Cash Flow Swap over the comparable periods.

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005 (Consolidated).

Net Sales. Consolidated net sales were $3,037.6 million for the year ended December 31, 2006 compared to $980.7 million for the 174 days ended June 23, 2005 and $1,454.3 million for the 233 days ended December 31, 2005. The increase of $602.6 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was primarily due to an increase in petroleum net sales of $613.2 million that resulted from significantly higher product prices ($384.1 million) and increased sales volumes ($229.1 million) over the comparable periods. Nitrogen fertilizer net sales decreased $10.5 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 due to decreased selling prices ($1.6 million) and a reduction in overall sales volumes ($8.9 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $2,443.4 million for the year ended December 31, 2006 as compared to $768.0 million for the 174 days ended June 23, 2005 and $1,168.1 million for the 233 days ended December 31, 2005. The increase of $507.3 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was primarily due to an increase in crude oil prices, sales volumes and the impact of FIFO accounting in our petroleum business. The nitrogen fertilizer business accounted for approximately $2.3 million of the increase in cost of products sold over the comparable period primarily related to increases in freight expense.

Depreciation and Amortization. Consolidated depreciation and amortization was $51.0 million for the year ended December 31, 2006 as compared to $1.1 million for the 174 days ended June 23, 2005 and $24.0 million for the 233 days ended December 31, 2005. The increase of $25.9 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was due to an increase in petroleum depreciation and amortization of $16.6 million and an increase in nitrogen fertilizer depreciation and amortization of $8.4 million.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Consolidated direct operating expenses exclusive of depreciation and amortization were $199.0 million for the year ended December 31, 2006 as compared to $80.9 million for the 174 days ended June 23, 2005 and

$85.3 million for the 233 days ended December 31, 2005. This increase of $32.8 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was due to an increase in petroleum direct operating expenses of $26.5 million and an increase in nitrogen fertilizer direct operating expenses of $6.2 million.

Selling, General and Administrative Expenses Exclusive of Depreciation and Amortization. Consolidated selling, general and administrative expenses were $62.6 million for the year ended December 31, 2006 as compared to $18.4 million for the 174 days ended June 23, 2005 and $18.4 million for the 233 days ended December 31, 2005. Consolidated selling, general and administrative expenses for the 174 days ended June 23, 2005 were negatively impacted by certain expenses associated with $3.3 million of unearned compensation related to the management equity of Immediate Predecessor in relation to the Subsequent Acquisition. Adjusting for this expense, consolidated selling, general and administrative expenses increased $29.1 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005. This variance was primarily the result of increases in administrative labor related to increased headcount and share-based compensation ($18.6 million), office costs ($1.3 million), letter of credit fees due under our $150.0 million funded letter of credit facility utilized as collateral for the Cash Flow Swap which was not in place for approximately six months in the comparable period ($2.1 million), public relations expense ($0.5 million) and outside services expense ($2.4 million).

Operating Income. Consolidated operating income was $281.6 million for the year ended December 31, 2006 as compared to $112.3 million for the 174 days ended June 23, 2005 and $158.5 million for the 233 days ended December 31, 2005. For the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005, petroleum operating income increased $45.9 million and nitrogen fertilizer operating income decreased by $34.2 million.

Interest Expense. We reported consolidated interest expense for the year ended December 31, 2006 of $43.9 million as compared to interest expense of $7.8 million for the 174 days ended June 23, 2005 and $25.0 million for the 233 days ended December 31, 2005. This 34% increase for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was the direct result of increased average borrowings over the comparable periods associated with both our credit facility dated December 28, 2006 and our borrowing facility completed in association with the Subsequent Acquisition and an increase in the actual rate of our borrowings due primarily to increases both in index rates (LIBOR and prime rate) and applicable margins. See Liquidity and Capital Resources Debt. The comparability of interest expense during the comparable periods has been impacted by the differing capital structures of Successor and Immediate Predecessor periods. See Factors Affecting Comparability of Our Financial Results.

Interest Income. Interest income was $3.5 million for the year ended December 31, 2006 as compared to $0.5 million for the 174 days ended June 23, 2005 and $1.0 million for the 233 days ended December 31, 2005. The increase for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005 was primarily due to larger cash balances and higher yields on invested cash.

Gain (loss) on Derivatives. For the year ended December 31, 2006, we reported $94.5 million in gains on derivatives. This compares to a $7.7 million loss on derivatives for the 174 days ended June 23, 2005 and a $316.1 million loss on derivatives for the 233 days ended December 31, 2005. This significant change in gain (loss) on derivatives for the year ended December 31, 2006 as compared to the combined period ended December 31, 2005 was primarily attributable to our Cash Flow Swap and the accounting treatment for all of our derivative transactions. We determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Since the Cash Flow Swap had a significant term remaining as of December 31, 2006 (approximately three years and six months) and the NYMEX crack spread that is the basis for the underlying swap contracts that comprised the Cash Flow Swap had declined during this period, the unrealized gains on the Cash Flow Swap increased significantly. The $323.7 million loss on derivatives during the combined period ended December 31, 2005 is inclusive of the expensing of a $25.0 million option entered into by Successor for the purpose of hedging certain levels of refined product margins. At closing of the Subsequent Acquisition, we determined that this option was not economical and we allowed the option to expire worthless, which resulted in the expensing of the associated premium during the year ended December 31, 2005. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

Extinguishment of Debt. On December 28, 2006, Coffeyville Acquisition LLC refinanced its existing first lien credit facility and second lien credit facility and raised $1.075 billion in long-term debt commitments under the new credit facility. See Liquidity and Capital Resources Debt. As a result of the retirement of the first and second lien credit facilities with the proceeds of the credit facility, we recognized $23.4 million as a loss on extinguishment of debt in 2006. On June 24, 2005 and in connection with the acquisition of Immediate Predecessor by Coffeyville Acquisition LLC, we raised $800.0 million in long-term debt commitments under both the first lien credit facility and second lien credit facility. See Factors Affecting Comparability of Our Financial Results and Liquidity and Capital Resources Debt. As a result of the retirement of Immediate Predecessor s outstanding indebtedness consisting of $150.0 million term loan and revolving credit facilities, we recognized $8.1 million as a loss on extinguishment of debt in 2005.

Other Income (Expense). For the year ended December 31, 2006, other expense was $0.9 million as compared to other expense of $0.8 million for the 174 days ended June 23, 2005 and other expense of $0.6 million for the 233 days ended December 31, 2005.

Provision for Income Taxes. Income tax expense for the year ended December 31, 2006 was $119.8 million, or 38.5% of earnings before income taxes, as compared to a tax benefit of $26.9 million, or 28.7% of earnings before income taxes, for the combined periods ended December 31, 2005. The effective tax rate for 2005 was impacted by a realized loss on option agreements that expired unexercised. Coffeyville Acquisition LLC was party to these agreements and the loss was incurred at that level which we effectively treated as a permanent non-deductible loss.

Net Income. For the year ended December 31, 2006, net income increased to $191.6 million as compared to net income of $52.4 million for the 174 days ended June 23, 2005 and a net loss of $119.2 million for the 233 days ended December 31, 2005. Net income increased $258.4 million for the year ended December 31, 2006 as compared to the combined periods ended December 31, 2005, primarily due to improved operating income in our petroleum operations and a significant change in the value of the Cash Flow Swap over the comparable periods.

Petroleum Business Results of Operations

Refining margin is a measurement calculated as the difference between net sales and cost of products sold (exclusive of depreciation and amortization). Refining margin is a non-GAAP measure that we believe is important to investors in evaluating our refinery s performance as a general indication of the amount above our cost of products that we are able to sell refined products. Each of the components used in this calculation (net sales and cost of products sold exclusive of depreciation and amortization) can be taken directly from our statement of operations. Our calculation of refining margin may differ from similar calculations of other companies in our industry, thereby limiting its

Table of Contents

usefulness as a comparative measure. The following table shows selected information about our petroleum business including refining margin:

	Immediate Predecessor 174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Successor Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
	(in millions)					
Petroleum Business:						
Net sales	$ 903.8	$ 1,363.4	$ 2,880.4	$ 2,806.2	$ 352.5	$ 1,168.5
Cost of product sold (exclusive of depreciation and amortization)	761.7	1,156.2	2,422.7	2,300.2	298.5	1,035.1
Direct operating expenses (exclusive of depreciation and amortization)	52.6	56.2	135.3	209.5	96.7	40.3
Net costs associated with flood				36.7		5.5
Depreciation and amortization	0.8	15.6	33.0	43.0	9.8	14.9
Gross profit (loss)	$ 88.7	$ 135.4	$ 289.4	$ 216.8	$ (52.5)	$ 72.7
Plus direct operating expenses (exclusive of depreciation and amortization)	52.6	56.2	135.3	209.5	96.7	40.3
Plus net costs associated with flood				36.7		5.5
Plus depreciation and amortization	0.8	15.6	33.0	43.0	9.8	14.9
Refining margin	$ 142.1	$ 207.2	$ 457.7	$ 506.0	$ 54.0	$ 133.4
Refining margin per crude oil throughput barrel	$ 9.28	$ 11.55	$ 13.27	$ 18.17	$ 12.69	$ 13.76
Gross profit (loss) per crude oil throughput barrel	$ 5.79	$ 7.55	$ 8.39	$ 7.79	$ (12.34)	$ 7.50
Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel	$ 3.44	$ 3.13	$ 3.92	$ 7.52	$ 22.73	$ 4.16
Operating income (loss)	76.7	123.0	245.6	144.9	(63.5)	63.6

Immediate Predecessor and Successor

	Combined	Successor			
	Year Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	2008 (unaudited)
	(dollars per barrel, except as indicated)				
Market Indicators					
West Texas Intermediate (WTI) crude oil	$ 56.70	$ 66.25	$ 72.36	$ 58.27	$ 97.82
NYMEX 2-1-1 Crack Spread	11.62	10.84	13.95	12.17	11.81
Crude Oil Differentials:					
WTI less WTS (sour)	4.73	5.36	5.16	4.26	4.63
WTI less Maya (heavy sour)	15.67	14.99	12.54	14.80	19.84
WTI less Dated Brent (foreign)	2.18	1.13	(0.02)	0.51	1.10
PADD II Group 3 versus NYMEX Basis:					
Gasoline	(0.53)	1.52	3.56	(0.54)	(1.46)
Heating Oil	3.20	7.42	7.95	8.77	3.65
PADD II Group 3 versus NYMEX Crack:					
Gasoline	10.53	12.26	18.34	12.43	4.95
Heating Oil	15.60	18.77	21.40	20.57	20.77

Table of Contents

	Immediate Predecessor and Successor Combined	Successor			
	Year Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	Three Months Ended March 31, 2008 (unaudited)
	(dollars per barrel, except as indicated)				
Company Operating Statistics					
Per barrel profit, margin and expense of crude oil throughput:					
Refining margin	$ 10.50	$ 13.27	$ 18.17	$ 12.69	$ 13.76
Gross profit	$ 6.74	$ 8.39	$ 7.79	$ (12.34)	$ 7.50
Direct operating expenses (exclusive of depreciation and amortization)	3.27	3.92	7.52	22.73	4.16
Per gallon sales price:					
Gasoline	1.61	1.88	2.20	1.59	2.45
Distillate	1.71	1.99	2.28	1.78	2.85

	Immediate Predecessor and Successor Combined December 31, 2005		Successor December 31, 2006		Successor December 31, 2007		Three Months Ended March 31, 2007		Three Months Ended March 31, 2008
Company tric Data	Barrels per Day	%	Barrels per Day	%	Barrels per Day	%	Barrels per Day (unaudited)	%	Barrels per Day (unaudit
n:									
oline	45,275	43.8	48,248	44.7	37,017	42.9	23,499	43.8	59,662
llate	39,997	38.7	42,175	39.0	34,814	40.4	21,976	40.9	48,591
r	18,090	17.5	17,608	16.3	14,370	16.7	8,214	15.3	17,361
roduction	103,362	100.0	108,031	100.0	86,201	100.0	53,689	100.0	125,614
t	91,097	92.6	94,524	92.1	76,285	93.0	47,267	92.7	106,530
nputs	7,246	7.4	8,067	7.9	5,780	7.0	3,716	7.3	13,197
stocks	98,343	100.0	102,591	100.0	82,065	100.0	50,983	100.0	119,727
t by crude									
	13,958,567	42.0	17,481,803	50.7	18,190,459	65.3	2,782,136	65.4	6,573,627

lium-sour	19,291,951	58.0	16,695,173	48.4	6,465,368	23.2	1,454,878	34.2	1,785,669
ır			324,312	0.9	3,188,133	11.5	17,016	0.4	1,334,889
e oil t	33,250,518	100.0	34,501,288	100.0	27,843,960	100.0	4,254,030	100.0	9,694,185

Three Months Ended March 31, 2008 Compared to the Year Ended March 31, 2007 (Petroleum Business).

Net Sales. Petroleum net sales were $1,168.5 million for the three months ended March 31, 2008 compared to $352.5 million for the three months ended March 31, 2007. The increase of $816.0 million during the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of significantly higher sales volumes ($592.1 million) and higher product prices ($223.9 million). Overall sales volumes of refined fuels for the three months ended March 31, 2008 increased 110% as compared to the three months ended March 31, 2007. The increased sales volume primarily resulted from a significant increase in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007. Our average sales price per gallon for the three months ended

March 31, 2008 for gasoline of $2.45 and distillate of $2.85 increased by 54% and 60%, respectively, as compared to the three months ended March 31, 2007.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $1,035.1 million for the three months ended March 31, 2008 compared to $298.5 million for the three months ended March 31, 2007. The increase of $736.6 million during the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of a significant increase in crude throughput due to refinery downtime from the refinery turnaround which began in February 2007 and was completed in April 2007. In addition to the refinery turnaround, higher crude oil prices, increased sales volumes and the impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil consumed for the three months ended March 31, 2008 was $92.35 compared to $51.98 for the comparable period of 2007, an increase of 78%. Sales volume of refined fuels increased 110% for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007. In addition, under our FIFO accounting method, changes in crude oil prices can cause fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the three months ended March 31, 2008, we had FIFO inventory gains of $20.0 million compared to FIFO inventory gains of $5.2 million for the comparable period of 2007. In 2007, as a result of the flood, our refinery exceeded the required average annual gasoline sulfur standard as mandated by our approved hardship waiver with the Environmental Protection Agency (EPA). In anticipation of a settlement with the EPA to resolve the non-compliance, we accrued a liability of approximately $3.5 million in the fourth quarter of 2007. During 2008, the matter was resolved with the EPA, and accordingly, the liability was reversed resulting in a reduction to cost of product sold (exclusive of depreciation and amortization) of approximately $3.5 million in the first quarter of 2008.

Refining margin per barrel of crude throughput increased from $12.69 for the three months ended March 31, 2007 to $13.76 for the three months ended March 31, 2008. Gross profit per barrel increased to $7.50 in the first quarter of 2008, up from a loss of $(12.34) in the equivalent period in 2007. The primary contributors to the positive variance in refining margin per barrel of crude throughput were an increase in FIFO inventory gains and increases in crude oil differentials over the comparable periods. Increased discounts for sour crude oils evidenced by the $0.37 per barrel, or 9%, increase in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, positively impacted refining margin for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007. Partially offsetting the positive effects of FIFO inventory gains and crude oil differentials was the 3% decrease ($0.36 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and negative regional differences between gasoline prices in our primary marketing region (the mid-continent area) and those of the NYMEX. The average gasoline basis for the three months ended March 31, 2008 decreased by $0.92 per barrel to ($1.46) per barrel compared to ($0.54) per barrel in the comparable period of 2007. The average distillate basis decreased by $5.12 per barrel to $3.65 per barrel compared to $8.77 per barrel in the comparable period of 2007.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $40.3 million for the three months ended March 31, 2008 compared to direct operating expenses of $96.7 million for the three months ended March 31, 2007. The decrease of $56.4 million for the three months ended March 31, 2008 compared to the three months ended March 31, 2007 was the result of decreases in expenses associated with refinery turnaround ($66.0 million) and direct labor ($1.7 million). These decreases in direct operating

expenses were partially offset by increases in expenses associated with utilities and energy ($4.3 million), repairs and maintenance ($3.0 million), production chemicals ($2.1 million), property taxes ($0.8 million) and environmental ($0.5 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude oil throughput for the three months ended March 31, 2008 decreased to $4.16 per barrel as compared to $22.73 per barrel for the three months ended March 31, 2007 principally due to the 2007 downtime at the refinery for planned major maintenance and the corresponding impact on overall crude oil throughput and production volume.

Net Costs Associated with Flood. Petroleum net costs associated with flood for the three months ended March 31, 2008 approximated $5.5 million. As the flood occurred in the second and third quarter of 2007, there were no flood related costs incurred in the first quarter of 2007. Total gross costs recorded for the three months ended March 31, 2008 were approximately $6.8 million. Of these gross costs approximately $3.0 million were associated with repair and other matters as a result of the physical damage to the refinery and approximately $3.8 million were associated with the environmental remediation and property damage. Total accounts receivable from insurers approximated $81.2 million at March 31, 2008, for which we believe collection is probable.

Depreciation and Amortization. Petroleum depreciation and amortization was $14.9 million for the three months ended March 31, 2008 as compared to $9.8 million for the three months ended March 31, 2007. This increase in petroleum depreciation and amortization for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of the completion of several large capital projects.

Operating Income (Loss). Petroleum operating income was $63.6 million for the three months ended March 31, 2008 as compared to an operating loss of $63.5 million for the three months ended March 31, 2007. This increase of $127.1 million from the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of the refinery turnaround which began in February 2007 and was completed in April 2007 and decreases in expenses associated with refinery turnaround ($66.0 million) and direct labor ($1.7 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with utilities and energy ($4.3 million), repairs and maintenance ($3.0 million), production chemicals ($2.1 million), taxes ($0.8 million) and environmental ($0.5 million).

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006 (Petroleum Business).

Net Sales. Petroleum net sales were $2,806.2 million for the year ended December 31, 2007 compared to $2,880.4 million for the year ended December 31, 2006. The decrease of $74.2 million from the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of significantly lower sales volumes ($576.9 million), partially offset by higher product prices ($502.7 million). Overall sales volumes of refined fuels for the year ended December 31, 2007 decreased 18% as compared to the year ended December 31, 2006. The decreased sales volume primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood. Our average sales price per gallon for the year ended December 31, 2007 for gasoline of $2.20 and distillate of $2.28 increased by 17% and 15%, respectively, as compared to the year ended December 31, 2006.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $2,300.2 million for the year ended December 31, 2007 compared to $2,422.7 million for the year ended December 31, 2006. The decrease of $122.5 million from the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of a significant reduction in crude throughput due to the refinery turnaround which began in February 2007 and was completed

in April 2007 and the refinery downtime resulting from the flood. In addition to the refinery turnaround and the flood, crude oil prices, reduced sales volumes and the impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil for the year ended December 31, 2007 was $70.06, compared to $61.71 for the comparable period of 2006, an increase of 14%. Sales volume of refined fuels decreased 18% for the year ended December 31, 2007 as compared to the year ended December 31, 2006 principally due to the refinery turnaround and flood. In addition, under our FIFO accounting method, changes in crude oil prices can cause fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the year ended December 31, 2007, we had FIFO inventory gains of $70.5 million compared to FIFO inventory losses of $7.6 million for the comparable period of 2006.

Refining margin per barrel of crude throughput increased from $13.27 for the year ended December 31, 2006 to $18.17 for the year ended December 31, 2007 primarily due to the 29% increase ($3.11 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and positive regional differences between gasoline and distillate prices in our primary marketing region (the mid-continent region) and those of the NYMEX. The average gasoline basis for the year ended December 31, 2007 increased by $2.04 per barrel to $3.56 per barrel compared to $1.52 per barrel in the comparable period of 2006. The average distillate basis for the year ended December 31, 2007 increased by $0.53 per barrel to $7.95 per barrel compared to $7.42 per barrel in the comparable period of 2006. The positive effect of the increased NYMEX 2-1-1 crack spreads and refined fuels basis over the comparable periods was partially offset by reductions in the crude oil differentials over the comparable periods. Decreased discounts for sour crude oils evidenced by the $0.20 per barrel, or 4%, decrease in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, negatively impacted refining margin for the year ended December 31, 2007 as compared to the year ended December 31, 2006.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $209.5 million for the year ended December 31, 2007 compared to direct operating expenses of $135.3 million for the year ended December 31, 2006. The increase of $74.2 million for the year ended December 31, 2007 compared to the year ended December 31, 2006 was the result of increases in expenses associated with repairs and maintenance related to the refinery turnaround ($67.3 million), taxes ($9.3 million), direct labor ($5.0 million), insurance ($2.4 million), production chemicals ($0.8 million) and outside services ($0.7 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($5.8 million), rent and lease ($2.4 million), environmental compliance ($1.4 million), operating materials ($0.8 million) and repairs and maintenance ($0.3 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the year ended December 31, 2007 increased to $7.52 per barrel as compared to $3.92 per barrel for the year ended December 31, 2006 principally due to refinery turnaround expenses and the related downtime associated with the turnaround and the flood and the corresponding impact on overall crude oil throughput and production volume.

Net Costs Associated with Flood. Petroleum net costs associated with the flood for the year ended December 31, 2007 approximated $36.7 million as compared to none for the year ended December 31, 2006. Total gross costs recorded for the year ended December 31, 2007 were approximately $138.0 million. Of these gross costs approximately $93.1 million were associated with repair and other matters as a result of the physical damage to the refinery and approximately $44.9 million were associated with the environmental remediation and property damage. Included in

the gross costs associated with the flood were certain costs that are excluded from the accounts receivable from insurers of $81.4 million at December 31, 2007, for which we believe collection is probable. The costs excluded from the accounts receivable from insurers were approximately $6.8 million recorded for depreciation for the temporarily idle facilities, $3.5 million of uninsured losses inside of the Company s deductibles, $2.8 million of uninsured expenses and $23.5 million recorded with respect to environmental remediation and property damage. As of December 31, 2007, $20.0 million of insurance recoveries recorded in 2007 had been collected and are not reflected in the accounts receivable from insurers balance at December 31, 2007.

Depreciation and Amortization. Petroleum depreciation and amortization was $43.0 million for the year ended December 31, 2007 as compared $33.0 million for the year ended December 31, 2006, an increase of $10.0 million over the comparable periods. During the restoration period for the refinery due to the flood, $6.8 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $6.8 million reclassification, the increase in petroleum depreciation and amortization for the year ended December 31, 2007 compared to the year ended December 31, 2006 would have been approximately $16.8 million. This adjusted increase in petroleum depreciation and amortization for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of the completion of the several large capital projects in late 2006 and during the year ended December 31, 2007.

Operating Income (Loss). Petroleum operating income was $144.9 million for the year ended December 31, 2007 as compared to operating income of $245.6 million for the year ended December 31, 2006. This decrease of $100.7 million from the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the flood. The turnaround negatively impacted daily refinery crude throughput and refined fuels production. Substantially all of the refinery s units damaged by the flood were back in operation by August 20, 2007. In addition, direct operating expenses increased substantially during the year ended December 31, 2007 related to refinery turnaround ($67.3 million), taxes ($9.3 million), direct labor ($5.0 million), insurance ($2.4 million), production chemicals ($0.8 million) and outside services ($0.7 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($5.8 million), rent and lease ($2.4 million), environmental compliance ($1.4 million), operating materials ($0.8 million) and repairs and maintenance ($0.3 million).

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005 (Petroleum Business).

Net Sales. Petroleum net sales were $2,880.4 million for the year ended December 31, 2006 compared to $903.8 million for the 174 days ended June 23, 2005 and $1,363.4 million for the 233 days ended December 31, 2005. The increase of $613.2 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 resulted from significantly higher product prices ($384.1 million) and increased sales volumes ($229.1 million) over the comparable periods. Our average sales price per gallon for the year ended December 31, 2006 for gasoline of $1.88 and distillate of $1.99 increased by 17% and 16%, respectively, as compared to the year ended December 31, 2005. Overall sales volumes of refined fuels for the year ended December 31, 2006 increased 9% as compared to the year ended December 31, 2005. The increased sales volume primarily resulted from higher production levels of refined fuels during the year ended December 31, 2006 as compared to the same period in 2005 because of our increased focus on process unit maximization and lower production levels in 2005 due to a scheduled reformer regeneration and minor maintenance in the coker unit and one of our crude units. Definitions of the terms coker unit and crude unit are contained in the section of this prospectus entitled Glossary of Selected Terms.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $2,422.7 million for the year ended December 31, 2006 compared to $761.7 million for the 174 days ended June 23, 2005 and $1,156.2 million for the 233 days ended December 31, 2005. The increase of $504.8 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of higher crude oil prices, increased sales volumes and the impact of FIFO accounting. Our average cost per barrel of crude oil for the year ended December 31, 2006 was $61.71, compared to $53.42 for the comparable period of 2005, an increase of 16%. Crude oil prices increased on average by 17% during the year ended December 31, 2006 as compared to the comparable period of 2005 due to the residual impact of Hurricanes Katrina and Rita on the refining sector, geopolitical concerns and strong demand for refined products. Sales volume of refined fuels increased 9% for the year ended December 31, 2006 as compared to the year ended December 31, 2005. In addition, under our FIFO accounting method, changes in crude oil prices can cause significant fluctuations in the inventory valuation of our crude oil, work in process and finished goods, thereby resulting in FIFO inventory gains when crude oil prices increase and FIFO inventory losses when crude oil prices decrease. For the year ended December 31, 2006, we reported FIFO inventory loss of $7.6 million compared to FIFO inventory gains of $18.6 million for the comparable period of 2005.

Refining margin per barrel of crude throughput increased from $10.50 for the year ended December 31, 2005 to $13.27 for the year ended December 31, 2006, due to increased discount for sour crude oils demonstrated by the $0.63, or 13%, increase in the spread between the WTI price, which is a market indicator for the price of light sweet crude, and the WTS price, which is an indicator for the price of sour crude, for the year ended December 31, 2006 as compared to the year ended December 31, 2005. In addition, positive regional differences between refined fuel prices in our primary marketing region (the mid-continent region) and those of the NYMEX, known as basis, significantly contributed to the increase in our consumed crack spread in the year ended December 31, 2006 as compared to the year ended December 31, 2005. The average distillate basis for the year ended December 31, 2006 increased by $4.22 per barrel to $7.42 per barrel compared to $3.20 per barrel in the comparable period of 2005. The average gasoline basis for the year ended December 31, 2006 increased by $2.05 per barrel to $1.52 per barrel in comparison to a negative basis of $0.53 per barrel in the comparable period of 2005.

Depreciation and Amortization. Petroleum depreciation and amortization was $33.0 million for the year ended December 31, 2006 as compared $0.8 million for the 174 days ended June 23, 2005 and $15.6 million for the 233 days ended December 31, 2005. The increase of $16.6 million for the year ended December 31, 2006 compared to the combined periods for the year ended December 31, 2005 was primarily the result of the step-up in our property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability of Our Financial Results.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance, labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $135.3 million for the year ended December 31, 2006 compared to direct operating expenses of $52.6 million for the 174 days ended June 23, 2005 and $56.2 million for the 233 days ended December 31, 2005. The increase of $26.5 million for the year ended December 31, 2006 compared to the combined periods for the year ended December 31, 2005 was the result of increases in expenses associated with direct labor ($3.3 million), rent and lease ($2.3 million), environmental compliance ($1.9 million), operating materials ($1.2 million), repairs and maintenance ($7.7 million), major scheduled turnaround ($4.0 million), chemicals ($3.0 million), insurance $(1.3 million) and outside services ($1.4 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the year ended December 31, 2006 increased to $3.92 per barrel as compared to $3.27 per barrel for the year ended December 31, 2005.

Operating Income. Petroleum operating income was $245.6 million for the year ended December 31, 2006 as compared to $76.7 million for the 174 days ended June 23, 2005 and $123.0 million for the 233 days ended December 31, 2005 This increase of $45.9 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 primarily resulted from higher refining margins due to improved crude differentials and strong gasoline and distillate basis during the comparable periods. The increase in operating income was somewhat offset by expenses associated with direct labor ($3.3 million), rent and lease ($2.3 million), environmental compliance ($1.9 million), operating materials ($1.2 million), repairs and maintenance ($7.7 million), major scheduled turnaround ($4.0 million), chemicals ($3.0 million), insurance ($1.3 million), outside services ($1.4 million) and depreciation and amortization ($16.6 million).

Nitrogen Fertilizer Business Results of Operations

The tables below provide an overview of the nitrogen fertilizer business results of operations, relevant market indicators and its key operating statistics during the past three years:

Nitrogen Fertilizer Business Financial Results	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Successor Year Ended December 31, 2006	Successor Year Ended December 31, 2007	Three Months Ended March 31, 2007 (unaudited)	Three Months Ended March 31, 2008 (unaudited)
	(in millions)					
Net sales	$ 79.3	$ 93.7	$ 162.5	$ 165.9	$ 38.6	$ 62.6
Cost of product sold (exclusive of depreciation and amortization)	9.1	14.5	25.9	13.0	6.1	8.9
Direct operating expenses (exclusive of depreciation and amortization)	28.3	29.2	63.7	66.7	16.7	20.3
Net costs associated with flood				2.4		
Depreciation and amortization	0.3	8.4	17.1	16.8	4.4	4.5
Operating income	35.3	35.7	36.8	46.6	9.3	26.0

Market Indicators	Year Ended December 31, 2005	2006	2007	Three Months Ended March 31, 2007	2008
Natural gas (dollars per MMBtu)	$ 9.01	$ 6.98	$ 7.12	$ 7.17	$ 8.74
Ammonia Southern Plains (dollars per ton)	356	353	409	389	590
UAN Corn Belt (dollars per ton)	212	197	288	239	371

Company Operating Statistics	Immediate Predecessor and Successor Combined Year Ended December 31, 2005	Successor Year Ended December 31, 2006	Year Ended December 31, 2007	Three Months Ended March 31, 2007	2008
Production (thousand tons):					
Ammonia	413.2	369.3	326.7	86.2	83.7
UAN	663.3	633.1	576.9	165.7	150.1
Total	1,076.5	1,002.4	903.6	251.9	233.8
Sales (thousand tons)(1):					
Ammonia	141.8	117.3	92.1	20.7	24.1
UAN	646.5	645.5	555.4	166.8	158.0
Total	788.3	762.8	647.5	187.5	182.1
Product pricing (plant gate) (dollars per ton)(1):					
Ammonia	$ 324	$ 338	$ 376	$ 347	$ 494
UAN	$ 173	$ 162	$ 211	$ 169	$ 262
On-stream factor(2):					
Gasifier	98.1%	92.5%	90.0%	91.8%	91.8%
Ammonia	96.7%	89.3%	87.7%	86.3%	90.7%
UAN	94.3%	88.9%	78.7%	89.4%	85.9%
Reconciliation to net sales (dollars in thousands):					
Freight in revenue	$ 15,010	$ 17,890	$ 13,826	$ 3,139	$ 4,022
Hydrogen revenue					5,291
Sales net plant gate	157,989	144,575	152,030	35,436	53,287
Total net sales	$ 172,999	$ 162,465	$ 165,856	$ 38,575	$ 62,600

(1) Plant gate sales per ton represents net sales less freight revenue divided by product sales volume in tons in the reporting period. Plant gate price per ton is shown in order to provide a pricing measure that is comparable across the fertilizer industry.

(2) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period. Excluding the impact of turnarounds at the fertilizer facility in the third quarter of 2006, the on-stream factors for the year ended December 31, 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN. Excluding the impact of the flood during the weekend of June 30, 2007, the on-stream factors for the year ended December 31, 2007 would have been 94.6% for gasifier, 92.4% for ammonia and 83.9% for UAN.

Three Months Ended March 31, 2008 compared to the Three Months Ended March 31, 2007 (Nitrogen Fertilizer Business).

Net Sales. Nitrogen fertilizer net sales were $62.6 million for the three months ended March 31, 2008 compared to $38.6 million for the three months ended March 31, 2007. The increase of $24.0 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was the result of higher plant gate prices, together with a change in intercompany accounting for hydrogen from cost of product sold (exclusive of depreciation and amortization) to net sales over the comparable periods, which eliminates in consolidation, partially offset by reductions in overall sales volume.

In regard to product sales volumes for the three months ended March 31, 2008, our nitrogen fertilizer operations experienced an increase of 17% in ammonia sales unit volumes and a decrease of 5% in UAN sales unit volumes. On-stream factors (total number of hours operated divided by total hours in the reporting period) for the gasification unit were unchanged over the comparable periods. On-stream factors for the ammonia unit were greater than the three months ended March 31, 2007. On-stream factors for the UAN plant were lower than the three month period ended March 31, 2007. During the three months ended March 31, 2008, all three primary nitrogen fertilizer units experienced approximately five days of downtime associated with repairs to the air separation unit. It is typical to experience brief outages in complex manufacturing operations such as our nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both FOB our plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or three months to three months. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the three months ended March 31, 2008 for ammonia and UAN were greater than plant gate prices for the comparable period of 2007 by 43% and 55%, respectively. This dramatic increase in nitrogen fertilizer prices was not the direct result of an increase in natural gas prices, but rather the result of increased demand for nitrogen-based fertilizers due to the increased use of corn for the production of ethanol and an overall increase in prices for corn, wheat and soybeans, the primary row crops in our region. This increase in demand for nitrogen-based fertilizer has created an environment in which nitrogen fertilizer prices have disconnected from their traditional correlation to natural gas prices.

The demand for fertilizer is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers. Individual farmers make planting decisions based largely on the prospective profitability of a harvest, while the specific varieties and amounts of fertilizer they apply depend on factors like crop prices, their current liquidity, soil conditions, weather patterns and the types of crops planted.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold (excluding depreciation and amortization) for the three months ended March 31, 2008 was $8.9 million compared to $6.1 million for the three months ended March 31, 2007. The increase of $2.8 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of a change in accounting for hydrogen reimbursement. For the three months ended March 31, 2007, hydrogen reimbursement was included in cost of product sold (exclusive of depreciation and amortization). For the three months ended March 31, 2008, hydrogen has been included in net sales. These amounts eliminate in consolidation. Hydrogen is transferred from our nitrogen fertilizer operations to our petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our nitrogen fertilizer operations include costs associated with the actual operations of our nitrogen plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the three months ended March 31, 2008 were $20.3 million as compared to $16.7 million for the three months ended March 31, 2007. The increase of $3.6 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of increases in expenses associated with property taxes ($2.5 million), repairs and maintenance ($1.7 million), labor ($0.3 million), catalysts ($0.3 million) and outside services ($0.2 million). These increases in direct operating expenses were partially offset by decreases in expenses associated with utilities ($0.6 million), royalties and other ($0.4 million) and equipment rental ($0.3 million).

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $4.5 million for the three months ended March 31, 2008 as compared to $4.4 million for the three months ended March 31, 2007. Nitrogen fertilizer depreciation and amortization increased by approximately $0.1 million for the three months ended March 31, 2008 compared to the three months ended March 31, 2007.

Operating Income. Nitrogen fertilizer operating income was $26.0 million for the three months ended March 31, 2008 as compared to operating income of $9.3 million for the three months ended March 31, 2007. This increase of

$16.7 million for the three months ended March 31, 2008 as

Table of Contents

compared to the three months ended March 31, 2007 was primarily the result of increased fertilizer prices over the comparable periods. Additionally, decreased direct operating expenses associated with utilities ($0.6 million), royalties and other ($0.4 million) and equipment rental ($0.3 million) also contributed to the positive operating income comparison over the comparable periods. These decreases in expenses were partially offset by reduced sales volumes and increased direct operating expenses primarily the result of increases in taxes ($2.5 million), repairs and maintenance ($1.7 million), labor ($0.3 million), catalysts ($0.3 million) and outside services ($0.2 million).

Year Ended December 31, 2007 compared to the Year Ended December 31, 2006 (Nitrogen Fertilizer Business).

Net Sales. Nitrogen fertilizer net sales were $165.9 million for the year ended December 31, 2007 compared to $162.5 million for the year ended December 31, 2006. The increase of $3.4 million from the year ended December 31, 2007 as compared to the year ended December 31, 2006 was the result of reductions in overall sales volumes ($31.0 million) which were more than offset by higher plant gate prices ($34.4 million).

In regard to product sales volumes for the year ended December 31, 2007, our nitrogen operations experienced a decrease of 22% in ammonia sales unit volumes (25,283 tons) and a decrease of 14% in UAN sales unit volumes (90,095 tons). The decrease in ammonia sales volume was the result of decreased production volumes during the year ended December 31, 2007 relative to the comparable period of 2006 due to unscheduled downtime at our fertilizer plant and the transfer of hydrogen to our petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit. The transfer of hydrogen to our petroleum operations will decrease, to some extent during 2008 because the new continuous catalytic reformer will produce hydrogen.

On-stream factors (total number of hours operated divided by total hours in the reporting period) for all units of our nitrogen operations (gasifier, ammonia plant and UAN plant) were less than the comparable period primarily due to approximately eighteen days of downtime for all three primary nitrogen units associated with the flood, nine days of downtime related to compressor repairs in the ammonia unit and 24 days of downtime related to the UAN expander in the UAN unit. In addition, all three primary units also experienced brief and unscheduled downtime for repairs and maintenance during the year ended December 31, 2007. It is typical to experience brief outages in complex manufacturing operations such as our nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both FOB our plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or year to year. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the year ended December 31, 2007 for ammonia and UAN were greater than plant gate prices for the comparable period of 2006 by 11% and 30%, respectively. Our ammonia and UAN sales prices for product shipped during the year ended December 31, 2006 generally followed volatile natural gas prices; however, it is typical for the reported pricing in our fertilizer business to lag the spot market prices for nitrogen fertilizer due to forward price contracts. As a result, forward price contracts entered into the late summer and fall of 2005 (during a period of relatively high natural gas prices due to the impact of hurricanes Rita and Katrina) comprised a significant portion of the product shipped in the spring of 2006. However, as natural gas prices moderated in the spring and summer of 2006, nitrogen fertilizer prices declined and the spot and fill contracts entered into and shipped during this lower natural gas prices environment realized lower average plant gate price. Ammonia and UAN sales prices for the year ended December 31, 2007 decoupled from natural gas prices and increased sharply driven by increased demand for fertilizer due to the increased use of corn for the production of ethanol and an overall increase in prices for corn, wheat and soybeans, which are the primary row

crops in our region. This increase in demand for nitrogen fertilizer has created an environment in which nitrogen fertilizer prices have disconnected from their traditional correlation to natural gas.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of petroleum coke expense, hydrogen reimbursement and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the year ended December 31, 2007 was $13.0 million compared to $25.9 million for the year ended December 31, 2006. The decrease of $12.9 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of increased hydrogen reimbursement due to the transfer of hydrogen to our petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit and reduced freight expense partially offset by an increase in petroleum coke costs. In 2007, pet coke costs increased as the nitrogen fertilizer business purchased more pet coke from third parties than is typical as a result of the flood, which reduced our refinery s pet coke production.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Nitrogen fertilizer operations include costs associated with the actual operations of our nitrogen plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the year ended December 31, 2007 were $66.7 million as compared to $63.7 million for the year ended December 31, 2006. The increase of $3.0 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of increases in repairs and maintenance ($6.5 million), equipment rental ($0.6 million) environmental ($0.4 million), utilities ($0.3 million), and insurance ($0.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with turnaround ($2.6 million), royalties and other expense ($1.1 million), reimbursed expense ($0.6 million), catalyst ($0.3 million), chemicals ($0.3 million) and slag disposal ($0.2 million).

Net Costs Associated with Flood. Nitrogen fertilizer net costs associated with flood for the year ended December 31, 2007 approximated $2.4 million as compared to none for the year ended December 31, 2006. Total gross costs recorded as a result of the physical damage to the fertilizer plant for the year ended December 31, 2007 were approximately $5.7 million. Included in the gross costs associated with the flood were certain costs that are excluded from the accounts receivable from insurers of approximately $3.3 million at December 31, 2007, for which we believe collection is probable. The costs excluded from the accounts receivable from insurers were approximately $0.8 million recorded for depreciation for the temporarily idle facilities, $0.1 million of uninsured losses inside of the Company s deductibles and $1.5 million of uninsured expenses.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization decreased to $16.8 million for the year ended December 31, 2007 as compared to $17.1 million for the year ended December 31, 2006. During the restoration period for the nitrogen fertilizer operations due to the flood, $0.8 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $0.8 reclassification, nitrogen fertilizer depreciation and amortization would have increased by approximately $0.5 million for the year ended December 31, 2007 compared to the year ended December 31, 2006.

Operating Income. Nitrogen fertilizer operating income was $46.6 million for the year ended December 31, 2007 as compared to $36.8 million for the year ended December 31, 2006. This increase of $9.8 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of an increase in plant gate prices ($34.4 million), partially offset by reductions in overall sales volumes ($31.0). In addition, a $12.9 million reduction in cost of product sold excluding depreciation and amortization due to increased hydrogen reimbursement and reduced freight expense partially offset by an increase in petroleum coke costs contributed to the positive variance in operating income during for the year ended December 31, 2007 compared to the year ended December 31, 2006.

Partially offsetting the positive effects of plant gate prices and cost of product sold excluding depreciation and amortization was an increase in direct operating expenses associated with repairs and maintenance ($6.5 million), equipment rental ($0.6 million) environmental ($0.4 million), utilities ($0.3 million), and insurance ($0.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with turnaround ($2.6 million), royalties and other expense ($1.1 million), reimbursed expense ($0.6 million), catalyst ($0.3 million), chemicals ($0.3 million) and slag disposal ($0.2 million).

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005 (Nitrogen Fertilizer Business).

Net Sales. Nitrogen fertilizer net sales were $162.5 million for the year ended December 31, 2006 compared to $79.3 million for the 174 days ended June 23, 2005 and $93.7 million for the 233 days ended December 31, 2005. The decrease of $10.5 million from the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was the result of both decreases in selling prices ($1.6 million) and reductions in overall sales volumes ($8.9 million) of the fertilizer products as compared to the year ended December 31, 2005.

Net sales for the year ended December 31, 2006 included $121.1 million from the sale of UAN, $42.1 million from the sale of ammonia and $6.8 million from the sale of hydrogen to CVR Energy. Net sales for the year ended December 31, 2005 included $122.2 million from the sale of UAN, $48.6 million from the sale of ammonia and $2.7 million from the sale of hydrogen to CVR Energy.

In regard to product sales volumes for the year ended December 31, 2006, the nitrogen fertilizer operations experienced a decrease of 17% in ammonia sales unit volumes (24,500 tons) and a decrease of 0.2% in UAN sales unit volumes (988 tons). The decrease in ammonia sales volume was the result of decreased production volumes during the year ended December 31, 2006 relative to the comparable period of 2005 due to the scheduled turnaround at the nitrogen fertilizer plant during July 2006 and the transfer of hydrogen to our petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit.

On-stream factors (total number of hours operated divided by total hours in the reporting period) for all units of the nitrogen fertilizer operations (gasifier, ammonia plant and UAN plant) were less in 2006 than in 2005 primarily due to the scheduled turnaround in July 2006 and downtime in the ammonia plant due to a crack in the converter. It is typical to experience brief outages in complex manufacturing operations such as the nitrogen fertilizer plant which result in less than 100% on-stream availability for one or more specific units.

Plant gate prices are prices FOB the delivery point less any freight cost absorbed to deliver the product. We believe plant gate price is meaningful because the nitrogen fertilizer business sells products both FOB the plant gate (sold plant) and FOB the customer s designated delivery site (sold delivered) and the percentage of sold plant versus sold delivered can change month to month or year to year. The plant gate price provides a measure that is consistently comparable period to period. Plant gate prices for the year ended December 31, 2006 for ammonia were greater than plant gate prices for the comparable period of 2005 by 4%. In contrast to ammonia, UAN prices decreased for the year ended December 31, 2006 as compared to the year ended December 31, 2005 by 6%. The positive price comparisons for ammonia sales, given the dramatic decline in natural gas prices during the comparable periods, were the result of prepay contracts executed during the period of relatively high natural gas prices that resulted from the impact of hurricanes Katrina and Rita on an already tight natural gas market.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the year ended December 31, 2006 was $25.9 million compared to $9.1 million for the 174 days ended June 23, 2005 and $14.5 million for the 233 days ended December 31, 2005. The increase of $2.3 million for the

year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of increases in freight expense.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $17.1 million for the year ended December 31, 2006 as compared to $0.3 million for the 174 days ended June 23, 2005 and $8.4 million for the 233 days ended December 31, 2005. This increase of $8.4 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of the step-up in property, plant and equipment for the Subsequent Acquisition. See Factors Affecting Comparability.

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for the nitrogen fertilizer operations include costs associated with the actual operations of the nitrogen fertilizer plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses exclusive of depreciation and amortization for the year ended December 31, 2006 were $63.7 million as compared to $28.3 million for the 174 days ended June 23, 2005 and $29.2 million for the 233 days ended December 31, 2005. The increase of $6.2 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was primarily the result of increases in labor ($0.7 million), repairs and maintenance ($0.5 million), turnaround expenses ($2.6 million), outside services ($0.6 million), utilities ($2.3 million) and insurance ($0.5 million), partially offset by reductions in expenses related to catalyst ($0.6 million) and environmental ($0.8 million).

Operating Income. Nitrogen fertilizer operating income was $36.8 million for the year ended December 31, 2006 as compared to $35.3 million for the 174 days ended June 23, 2005 and $35.7 million for the 233 days ended December 31, 2005. This decrease of $34.2 million for the year ended December 31, 2006 as compared to the combined periods for the year ended December 31, 2005 was the result of reduced sales volumes, lower plant gate prices for UAN and increased direct operating expenses related to labor ($0.7 million), repairs and maintenance ($0.5 million), turnaround expenses ($2.6 million), outside services ($0.6 million), utilities ($2.3 million), insurance ($0.5 million) and depreciation ($8.4 million), partially offset by reductions in expenses related to catalyst ($0.6 million) and environmental ($0.8 million) and higher ammonia prices.

Liquidity and Capital Resources

Our primary sources of liquidity currently consist of cash generated from our operating activities, existing cash balances, our existing revolving credit facility and third party guarantees of obligations under the Cash Flow Swap as well as our convertible notes offering, if consummated, and the proceeds of our proposed senior secured credit facility, if entered into. Our ability to generate sufficient cash flows from our operating activities will continue to be primarily dependent on producing or purchasing, and selling, sufficient quantities of refined products at margins sufficient to cover fixed and variable expenses.

As of March 31, 2008 and June 16, 2008, we had cash, cash equivalents and short-term investments of $25.2 million and $71.4 million, respectively, and up to $112.6 million available under our revolving credit facility as of both dates. In the current crude oil price environment, working capital is subject to substantial variability from week-to-week and month-to-month. The payable to swap counterparty included in the consolidated balance sheet at March 31, 2008 was approximately $371.4 million, and the current portion included an increase of $32.6 million from December 31, 2007, resulting in an equal reduction in our working capital for the same period.

On June 30, 2007, our refinery and the nitrogen fertilizer plant were severely flooded and forced to conduct emergency shutdowns and evacuate. See Flood and Crude Oil Discharge. Our liquidity was significantly negatively impacted as a result of the reduction in cash provided by operations due to our temporary cessation of operations and the additional expenditures associated with the flood

115

and crude oil discharge. In order to provide immediate and future liquidity, on August 23, 2007 we deferred payments which were due to J. Aron under the terms of the Cash Flow Swap. The J. Aron deferred amounts of $123.7 million (plus accrued interest of $5.8 million as of June 1, 2008) are due on August 31, 2008. See Liquidity and Capital Resources Payment Deferrals Related to the Cash Flow Swap for additional information about the payment deferral. These deferrals are supported by third-party guarantees. In addition, we estimate that we will owe J. Aron approximately $54 million on July 8, 2008 for crude oil we settled with respect to the quarter ending June 30, 2008 based on June 16, 2008 pricing.

Our liquidity was enhanced during the fourth quarter of 2007 by the receipt of the net proceeds from our initial public offering. We intend to use the net proceeds from the convertible notes offering, if consummated, and the proposed senior secured credit facility, if entered into, for general corporate purposes, which may include using a portion of the proceeds to pay amounts owed to J. Aron under the Cash Flow Swap and for other future capital investments. If the convertible notes offering is not consummated and/or the proposed senior secured credit facility is not entered into, we intend to fund our operations through cash generated from our operating activities, existing cash balances, our existing revolving credit facility and third party guarantees of obligations under the Cash Flow Swap. We believe these capital resources will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next twelve months. However, our future capital expenditures and other cash requirements could be higher than we currently expect as a result of various factors. Additionally, our ability to generate sufficient cash from our operating activities depends on our future performance, which is subject to general economic, political, financial, competitive and other factors beyond our control.

Debt

Proposed Secured Credit Facility

Concurrently with the closing of this offering, we anticipate that Coffeyville Resources, LLC will enter into a new $25.0 million senior secured term loan (the proposed senior secured credit facility). We anticipate that the proposed senior secured credit facility will be secured by the same collateral that secures our existing Credit Facility and will contain covenants substantially similar to the Credit Facility described below. Although we have begun negotiations on the new credit facility, we have not entered into any agreement regarding the proposed senior secured credit facility, and as such, there is no guarantee that we will be enter into a credit facility on the terms described above or at all.

Credit Facility

On December 28, 2006, our subsidiary, Coffeyville Resources, LLC, entered into a credit facility (the Credit Facility) which provided financing of up to $1.075 billion. The Credit Facility consisted of $775.0 million of tranche D term loans, a $150.0 million revolving credit facility, and a funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap. On October 26, 2007, we repaid $280.0 million of the tranche D term loans with proceeds from our initial public offering. The Credit Facility is guaranteed by all of our subsidiaries and is secured by substantially all of their assets including the equity of our subsidiaries on a first-lien priority basis.

The tranche D term loans outstanding are subject to quarterly principal amortization payments of 0.25% of the outstanding balance commencing on April 1, 2007 and increasing to 23.5% of the outstanding principal balance on April 1, 2013 and the next two quarters, with a final payment of the aggregate outstanding balance on December 28, 2013.

The revolving credit facility of $150.0 million provides for direct cash borrowings for general corporate purposes and on a short-term basis. Letters of credit issued under the revolving credit facility are subject to a $75.0 million sub-limit. The revolving loan commitment expires on December 28, 2012. The borrower has an option to extend this maturity upon written notice to the lenders; however, the revolving loan maturity cannot be extended beyond the final maturity of the term loans, which is

December 28, 2013. As of March 31, 2008, we had available $112.6 million under the revolving credit facility. As of June 16, 2008, we had available $112.6 million under the revolving credit facility.

The $150.0 million funded letter of credit facility provides credit support for our obligations under the Cash Flow Swap. The funded letter of credit facility is fully cash collateralized by the funding by the lenders of cash into a credit linked deposit account. This account is held by the funded letter of credit issuing bank. Contingent upon the requirements of the Cash Flow Swap, the borrower has the ability to reduce the funded letter of credit at any time upon written notice to the lenders. The funded letter of credit facility expires on December 28, 2010.

The Credit Facility incorporates the following pricing by facility type:

Tranche D term loans bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 2.25%, or, at the borrower s option, (b) LIBOR plus 3.25% (with step-downs to the prime rate/federal funds rate plus 1.75% or 1.50% or LIBOR plus 2.75% or 2.50%, respectively, upon achievement of certain rating conditions).

Revolving loan borrowings bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 2.25%, or, at the borrower s option, (b) LIBOR plus 3.25% (with step-downs to the prime rate/federal funds rate plus 1.75% or 1.50% or LIBOR plus 2.75% or 2.50%, respectively, upon achievement of certain rating conditions).

Letters of credit issued under the $75.0 million sub-limit available under the revolving loan facility are subject to a fee equal to the applicable margin on revolving LIBOR loans owing to all revolving lenders and a fronting fee of 0.25% per annum owing to the issuing lender.

Funded letters of credit are subject to a fee equal to the applicable margin on term LIBOR loans owed to all funded letter of credit lenders and a fronting fee of 0.125% per annum owing to the issuing lender. The borrower is also obligated to pay a fee of 0.10% to the administrative agent on a quarterly basis based on the average balance of funded letters of credit outstanding during the calculation period, for the maintenance of a credit-linked deposit account backstopping funded letters of credit.

In addition to the fees stated above, the Credit Facility requires the borrower to pay 0.50% per annum in commitment fees on the unused portion of the revolving loan facility.

The Credit Facility requires the borrower to prepay outstanding loans, subject to certain exceptions, with:

100% of the net asset sale proceeds received from specified asset sales and net insurance/ condemnation proceeds, if the borrower does not reinvest those proceeds in assets to be used in its business or make other permitted investments within 12 months or if, within 12 months of receipt, the borrower does not contract to reinvest those proceeds in assets to be used in its business or make other permitted investments within 18 months of receipt, each subject to certain limitations;

100% of the cash proceeds from the incurrence of specified debt obligations; and

75% of consolidated excess cash flow less 100% of voluntary prepayments made during the fiscal year; provided that with respect to any fiscal year commencing with fiscal 2008 this percentage will be reduced to 50% if the total leverage ratio at the end of such fiscal year is less than 1.50:1.00 or 25% if the total leverage ratio as of the end of such fiscal year is less than 1.00:1.00.

Mandatory prepayments will be applied first to the term loan, second to the swing line loans, third to the revolving loans, fourth to outstanding reimbursement obligations with respect to revolving letters of credit and funded letters of credit, and fifth to cash collateralize revolving letters of credit and funded letters of credit. Voluntary prepayments of loans under the Credit Facility are permitted, in whole or in part, at the borrower s option, without premium or penalty.

The Credit Facility contains customary covenants. These agreements, among other things, restrict, subject to certain exceptions, the ability of Coffeyville Resources, LLC and its subsidiaries to incur additional indebtedness, create liens on assets, make restricted junior payments, enter into agreements that restrict subsidiary distributions, make investments, loans or advances, engage in mergers, acquisitions or sales of assets, dispose of subsidiary interests, enter into sale and leaseback transactions, engage in certain transactions with affiliates and stockholders, change the business conducted by the credit parties, and enter into hedging agreements. The Credit Facility provides that Coffeyville Resources, LLC may not enter into commodity agreements if, after giving effect thereto, the exposure under all such commodity agreements exceeds 75% of Actual Production (the borrower s estimated future production of refined products based on the actual production for the three prior months) or for a term of longer than six years from December 28, 2006. In addition, the borrower may not enter into material amendments related to any material rights under the Cash Flow Swap or the Partnership s partnership agreement without the prior written approval of the lenders. These limitations are subject to critical exceptions and exclusions and are not designed to protect investors in our common stock.

The Credit Facility also requires the borrower to maintain certain financial ratios as follows:

Fiscal Quarter Ending	**Minimum Interest Coverage Ratio**	**Maximum Leverage Ratio**
June 30, 2008	3.25:1.00	3.00:1.00
September 30, 2008	3.25:1.00	2.75:1.00
December 31, 2008	3.25:1.00	2.50:1.00
March 31, 2009 and thereafter	3.75:1.00	2.25:1.00 to December 31, 2009 2.00:1.00 thereafter

The computation of these ratios is governed by the specific terms of the Credit Facility and may not be comparable to other similarly titled measures computed for other purposes or by other companies. The minimum interest coverage ratio is the ratio of consolidated adjusted EBITDA to consolidated cash interest expense over a four quarter period. The maximum leverage ratio is the ratio of consolidated total debt to consolidated adjusted EBITDA over a four quarter period. The computation of these ratios requires a calculation of consolidated adjusted EBITDA. In general, under the terms of our Credit Facility, consolidated adjusted EBITDA is calculated by adding consolidated net income, consolidated interest expense, income taxes, depreciation and amortization, other non- cash expenses, any fees and expenses related to permitted acquisitions, any non-recurring expenses incurred in connection with the issuance of debt or equity, management fees, any unusual or non-recurring charges up to 7.5% of consolidated adjusted EBITDA, any net after-tax loss from disposed or discontinued operations, any incremental property taxes related to abatement non-renewal, any losses attributable to minority equity interests and major scheduled turnaround expenses. As of the date of this prospectus, we were in compliance with our covenants under the Credit Facility.

Table of Contents

We present consolidated adjusted EBITDA because it is a material component of material covenants within our current Credit Facility and significantly impacts our liquidity and ability to borrow under our revolving line of credit. However, consolidated adjusted EBITDA is not a defined term under GAAP and should not be considered as an alternative to operating income or net income as a measure of operating results or as an alternative to cash flows as a measure of liquidity. Consolidated adjusted EBITDA is calculated under the Credit Facility as follows:

Consolidated Financial Results	Immediate Predecessor and Successor Combined (Non-GAAP)	Successor			
	Year Ended December 31,			Three Months Ended March 31,	
	2005	2006	2007	2007	2008
	(unaudited)	(in millions)		(unaudited in millions)	
Net income (loss)	$ (66.8)	$ 191.6	$ (67.6)	$ (154.4)	$ 22.2
Plus:					
Depreciation and amortization	25.1	51.0	68.4	14.2	19.6
Interest expense	32.8	43.9	61.1	11.9	11.3
Income tax expense (benefit)	(26.9)	119.8	(88.5)	(47.3)	6.9
Loss on extinguishment of debt	8.1	23.4	1.3		
Inventory fair market value adjustment	16.6				
Funded letters of credit expenses and interest rate swap not included in interest expense	2.3		1.8		0.9
Major scheduled turnaround expense		6.6	76.4	66.0	
Loss on termination of Swap	25.0				
Unrealized (gain) or loss on derivatives	229.8	(128.5)	113.5	126.9	18.9
Non-cash compensation expense for equity awards	1.8	16.9	43.5	3.7	(0.4)
(Gain) or loss on disposition of fixed assets		1.2	1.3		
Expenses related to acquisition	3.5				
Minority interest in subsidiaries			(0.2)	(0.7)	
Management fees	2.3	2.3	11.7	0.5	
Consolidated adjusted EBITDA	$ 253.6	$ 328.2	$ 222.7	$ 20.8	$ 79.4

In addition to the financial covenants summarized in the table above, the Credit Facility restricts the capital expenditures of Coffeyville Resources, LLC to $125.0 million in 2008, $125.0 million in 2009, $80.0 million in 2010, and $50.0 million in 2011 and thereafter. The capital expenditures covenant includes a mechanism for carrying over the excess of any previous year s capital expenditure limit. The capital expenditures limitation will not apply for any fiscal year commencing with fiscal 2009 if the borrower obtains a total leverage ratio of less than or equal to 1.25:1.00 for any quarter commencing with the quarter ending December 31, 2008. We believe the limitations on our capital expenditures imposed by the Credit Facility should allow us to meet our current capital expenditure needs. However, if future events require us or make it beneficial for us to make capital expenditures beyond those currently planned, we would need to obtain consent from the lenders under our Credit Facility.

The Credit Facility also contains customary events of default. The events of default include the failure to pay interest and principal when due, including fees and any other amounts owed under the Credit Facility, a breach of certain covenants under the Credit Facility, a breach of any representation or warranty contained in the Credit Facility, any default under any of the documents entered into in connection with the Credit Facility, the failure to pay principal or interest or any other amount payable under other debt arrangements in an aggregate amount of at least $20.0 million, a breach or default with respect to material terms under other debt arrangements in an aggregate amount of at least $20.0 million which results in the debt becoming payable or declared due and payable before its stated maturity, a breach or default under the Cash Flow Swap that would permit the holder or holders to terminate the Cash Flow Swap, events of bankruptcy, judgments and attachments exceeding $20.0 million, events relating to employee benefit plans resulting in liability in excess of $20.0 million, a change in control, the guarantees, collateral documents or the Credit Facility failing to be in full force and effect or being declared null and void, any guarantor repudiating its obligations, the failure of the collateral agent under the Credit Facility to have a lien on any material portion of the collateral, and any party under the Credit Facility (other than the agent or lenders under the Credit Facility) contesting the validity or enforceability of the Credit Facility.

Under the terms of our Credit Facility, our initial public offering was deemed a Qualified IPO because the offering generated more than $250.0 million of gross proceeds and we used the proceeds of the offering to repay at least $275.0 million of term loans under the Credit Facility. As a result of our Qualified IPO, the interest margin on LIBOR loans may in the future decrease from 3.25% to 2.75% (if we have credit ratings of B2/B) or 2.50% (if we have credit ratings of B1/B+). Interest on base rate loans will similarly be adjusted. In addition, as a result of our Qualified IPO, (1) we will be allowed to borrow an additional $225.0 million under the Credit Facility after June 30, 2008 to finance capital enhancement projects if we are in pro forma compliance with the financial covenants in the Credit Facility and the rating agencies confirm our ratings, (2) we will be allowed to pay an additional $35.0 million of dividends each year, if our corporate family ratings are at least B2 from Moody s and B from S&P, (3) we will not be subject to any capital expenditures limitations commencing with fiscal 2009 if our total leverage ratio is less than or equal to 1.25:1 for any quarter commencing with the quarter ending December 31, 2008, and (4) at any time after March 31, 2008 we will be allowed to reduce the Cash Flow Swap to not less than 35,000 barrels a day for fiscal 2008 and terminate the Cash Flow Swap for any year commencing with fiscal 2009, so long as our total leverage ratio is less than or equal to 1.25:1 and we have a corporate family rating of at least B2 from Moody s and B from S&P.

The Credit Facility is subject to an intercreditor agreement among the lenders and the Cash Flow Swap provider, which deal with, among other things, priority of liens, payments and proceeds of sale of collateral.

At March 31, 2008 and December 31, 2007, funded long-term debt, including current maturities, totaled $488.0 million and $489.2 million, respectively, of tranche D term loans. Other commitments at March 31, 2008 and December 31, 2007 included a $150.0 million funded letter of credit facility and a $150.0 million revolving credit facility. As of March 31, 2008, the commitment outstanding on the revolving credit facility was $37.4 million, including $5.8 million in letters of credit in support of certain environmental obligations and $31.6 million in letters of credit to secure transportation services for crude oil. As of December 31, 2007, the commitment outstanding on the revolving credit facility was $39.4 million, including $5.8 million in letters of credit in support of certain environmental obligations, $3.0 million in support of surety bonds in place to support state and federal excise tax for refined fuels, and $30.6 million in letters of credit to secure transportation services for crude oil.

August 2007 Credit Facilities

The 2007 flood and crude oil discharge had a significant negative effect on our liquidity in July/August 2007. We did not generate any material revenue while our facilities were shut down due to the flood, but we incurred and continue to incur significant flood repair and cleanup costs, as well as

incremental legal, public relations and crisis management costs. We also had significant contractual obligations to purchase gathered crude oil. We also owed J. Aron approximately $123.7 million under the Cash Flow Swap, which we deferred to January 31, 2008 (see Payment Deferrals Related to Cash Flow Swap below). In addition, although we believe that we will recover substantial sums under our insurance policies, we are not sure of the ultimate amount or timing of such recovery.

As a result of these factors, in August 2007 our subsidiaries entered into three new credit facilities.

$25.0 Million Secured Facility. Coffeyville Resources, LLC entered into a new $25.0 million senior secured term loan (the $25.0 million secured facility). The facility was secured by the same collateral that secures our existing Credit Facility. Interest was payable in cash, at our option, at the base rate plus 1.00% or at the reserve adjusted eurodollar rate plus 2.00%.

$25.0 Million Unsecured Facility. Coffeyville Resources, LLC entered into a new $25.0 million senior unsecured term loan (the $25.0 million unsecured facility). Interest was payable in cash, at our option, at the base rate plus 1.00% or at the reserve adjusted eurodollar rate plus 2.00%.

$75.0 Million Unsecured Facility. Coffeyville Refining & Marketing Holdings, Inc. entered into a new $75.0 million senior unsecured term loan (the $75.0 million unsecured facility). Drawings could be made from time to time in amounts of at least $5.0 million. Interest accrued, at our option, at the base rate plus 1.50% or at the reserve adjusted eurodollar rate plus 2.50%. Interest was paid by adding such interest to the principal amount of loans outstanding. In addition, a commitment fee equal to 1.00% accrued and was paid by adding such fees to the principal amount of loans outstanding. No amounts were drawn under this facility.

All indebtedness outstanding under the $25.0 million secured facility and the $25.0 million unsecured facility was repaid in October 2007 with the proceeds of our initial public offering, and all three facilities were terminated at that time.

Payment Deferrals Related to Cash Flow Swap

As a result of the flood and the temporary cessation of our operations on June 30, 2007, Coffeyville Resources, LLC entered into several deferral agreements with J. Aron with respect to the Cash Flow Swap. These deferral agreements deferred to January 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. J. Aron has agreed to further defer these payments to August 31, 2008. We are required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts, but as of March 31, 2008 we were not required to prepay any portion of the deferred amount.

On June 26, 2007, Coffeyville Resources, LLC and J. Aron & Company entered into a letter agreement in which J. Aron deferred to August 7, 2007 a $45.0 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. We agreed to pay interest on the deferred amount at the rate of LIBOR plus 3.25%.

On July 11, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to July 25, 2007 a separate $43.7 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. J. Aron deferred the $43.7 million payment on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one-half of the payment and (b) interest accrued on the $43.7 million from July 9, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On July 26, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to September 7, 2007 both the $45.0 million payment due August 7, 2007 (and accrued interest) and the $43.7 million payment due July 25, 2007 (and accrued interest). J. Aron deferred these payments on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one-half of the payments and (b) interest accrued on the amounts from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to January 31, 2008 the $45.0 million payment due September 7, 2007 (and accrued interest), the $43.7 million payment due September 7, 2007 (and accrued interest) and the $35.0 million payment which we owed to J. Aron under the Cash Flow Swap to settle hedged volume through August 15, 2007. J. Aron deferred these payments (totaling $123.7 million, plus accrued interest) on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts to the date of payment at the rate of LIBOR plus 1.50%.

Nitrogen Fertilizer Limited Partnership

The managing general partner of the Partnership may, from time to time, seek to raise capital through a public or private offering of limited partner interests in the Partnership. Any decision to pursue such a transaction would be made in the discretion of the managing general partner, not us, and any proceeds raised in a primary offering would be for the benefit of the Partnership, not us (although in some cases, depending on the structure of the transaction, the Partnership might remit proceeds to us). If the managing general partner elects to pursue a public or private offering of limited partner interests in the Partnership, we expect that any such transaction would require amendments to our Credit Facility, as well as to the Cash Flow Swap, in order to remove the Partnership and its subsidiaries as obligors under such instruments. Any such amendments could result in significant changes to our Credit Facility s pricing, mandatory repayment provisions, covenants and other terms and could result in increased interest costs and require payment by us of additional fees. We have agreed to use our commercially reasonable efforts to obtain such amendments if the managing general partner elects to cause the Partnership to pursue a public or private offering and gives us at least 90 days written notice.

However, we cannot assure you that we will be able to obtain any such amendment on terms acceptable to us or at all. If we are not able to amend our Credit Facility on terms satisfactory to us, we may need to refinance it with other facilities. We will not be considered to have used our commercially reasonable efforts to obtain such amendments if we do not effect the requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us. In order to effect the requested amendments, we may require that (1) the Partnership s initial public or private offering generate at least $140.0 million in net proceeds to us and (2) the Partnership raise an amount of cash (from the issuance of equity or incurrence of indebtedness) equal to $75.0 million minus the amount of capital expenditures for which it will reimburse us from the proceeds of its initial public or private offering and to distribute that cash to us prior to, or concurrently with, the closing of its initial public or private offering. If the managing general partner sells interests to third party investors, we expect that the Partnership may at such time seek to enter into its own credit facility.

The Partnership filed a registration statement in February 2008 for an initial public offering of its common units. On June 13, 2008, we announced that the managing general partner of the Partnership has decided to postpone indefinitely the Partnership s initial public offering due to current market conditions for master limited partnerships. We believe maintaining the fertilizer business within the Company provides greater value for CVR Energy shareholders than would be the case if the Partnership became a publicly-traded partnership at this time. The Partnership subsequently

Table of Contents

requested that the registration statement be withdrawn. The Partnership may elect to move forward with a public or private offering in the future. Any future public or private offering by the Partnership would be made solely at the discretion of the Partnership s managing general partner, subject to our specified joint management rights, and would be subject to market conditions and negotiation of terms acceptable to the Partnership s managing general partner. In connection with the Partnership s initial public or private offering, if any, the Partnership may require us to include a sale of a portion of our interests in the Partnership. If the Partnership becomes a public company, we may consider a secondary offering of interests which we own (either in connection with a public offering by the Partnership, but subject to priority rights in favor of the Partnership, or following completion of the Partnership s initial public offering, if any) or in a private placement. We cannot assure you that any such transaction will be consummated. Neither the consent of the managing general partner nor the consent of the Partnership is required for any sale of our interests in the Partnership, other than customary blackout periods relating to offerings by the Partnership. Any proceeds raised would be for our benefit. The Partnership has granted us registration rights which will require the Partnership to register our interests with the SEC at our request from time to time (following any public offering by the Partnership), subject to various limitations and requirements. We cannot assure you that any such transaction will be consummated.

Capital Spending

We divide our capital spending needs into two categories: non-discretionary, which is either capitalized or expensed, and discretionary, which is capitalized. Non-discretionary capital spending, such as for planned turnarounds and other maintenance, is required to maintain safe and reliable operations or to comply with environmental, health and safety regulations. The total non-discretionary capital spending needs for our refinery business and the nitrogen fertilizer business, including major scheduled turnaround expenses, were approximately $170 million in 2006 and $218 million in 2007 and we estimate that the total non-discretionary capital spending needs of our refinery business and the nitrogen fertilizer business will be approximately $279 million in the aggregate over the three-year period beginning 2008. These estimates include, among other items, the capital costs necessary to comply with environmental regulations, including Tier II gasoline standards and on-road diesel regulations. As described above, our credit facility limits the amount we can spend on capital expenditures.

Compliance with the Tier II gasoline and on-road diesel standards required us to spend approximately $133 million during 2006 and approximately $103 million during 2007, and we estimate that compliance will require us to spend approximately $68 million in the aggregate between 2008 and 2010. These amounts are reflected in the table below under Environmental and safety capital needs. See Business Environmental Matters Fuel Regulations Tier II, Low Sulfur Fuels.

The following table sets forth our estimate of non-discretionary spending for our refinery business and the nitrogen fertilizer business for the years presented as of March 31, 2008 (other than 2006 and 2007 which reflect actual spending). Capital spending for the nitrogen fertilizer business has been and will be determined by the managing general partner of the Partnership. The data contained in the table below represents our current plans, but these plans may change as a result of unforeseen

Table of Contents

circumstances and we may revise these estimates from time to time or not spend the amounts in the manner allocated below.

Petroleum Business

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental and safety capital needs	$ 144.6	$ 121.8	$ 46.0	$ 53.9	$ 23.5	$ 2.6	$ 2.1	$ 394.5
Sustaining capital needs	11.8	14.9	22.0	29.8	22.3	22.0	22.0	144.8
	156.4	136.7	68.0	83.7	45.8	24.6	24.1	539.3
Major scheduled turnaround expenses	4.0	76.4			50.0			130.4
Total estimated non-discretionary spending	$ 160.4	$ 213.1	$ 68.0	$ 83.7	$ 95.8	$ 24.6	$ 24.1	$ 669.7

Nitrogen Fertilizer Business

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental and safety capital needs	$ 0.1	$ 0.5	$ 2.2	$ 4.5	$ 2.6	2.7	3.8	$ 16.4
Sustaining capital needs	6.6	3.9	9.7	3.1	4.5	4.8	4.3	36.9
	6.7	4.4	11.9	7.6	7.1	7.5	8.1	53.3
Major scheduled turnaround expenses	2.6		2.8		2.6		2.8	10.8
Total estimated non-discretionary spending	$ 9.3	$ 4.4	$ 14.7	$ 7.6	$ 9.7	$ 7.5	$ 10.9	$ 64.1

Combined

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental and safety capital needs	$ 144.7	$ 122.3	$ 48.2	$ 58.4	$ 26.1	5.3	5.9	$ 410.9
Sustaining capital needs	18.4	18.8	31.7	32.9	26.8	26.8	26.3	181.7
	163.1	141.1	79.9	91.3	52.9	32.1	32.2	592.6
	6.6	76.4	2.8		52.6		2.8	141.2

Major scheduled turnaround expenses								
Total estimated non-discretionary spending	$ 169.7	$ 217.5	$ 82.7	$ 91.3	$ 105.5	$ 32.1	$ 35.0	$ 733.8

We undertake discretionary capital spending based on the expected return on incremental capital employed. Discretionary capital projects generally involve an expansion of existing capacity, improvement in product yields, and/or a reduction in direct operating expenses. As of December 31, 2007, we had committed approximately $14 million towards discretionary capital spending in 2008. Other than the nitrogen fertilizer plant expansion project referred to below, we anticipate that our discretionary capital spending will average approximately $35 million per year between 2008 and 2012.

The Partnership is currently moving forward with an approximately $120 million fertilizer plant expansion, of which approximately $11 million was incurred as of March 31, 2008. We estimate this expansion will increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium priced UAN by approximately 50%. Management currently expects to complete this expansion in July 2010. This project is also expected to improve the cost structure of the nitrogen fertilizer business by eliminating the need for rail shipments of ammonia, thereby avoiding anticipated cost increases in such transport.

Table of Contents

Cash Flows

The following table sets forth our cash flows for the periods indicated below:

	Immediate Predecessor	Successor				
	174 Days Ended	233 Days Ended December 31,	Year Ended December 31,		Three Months Ended March 31,	
	June 23, 2005	2005	2006	2007	2007 (unaudited)	2008 (unaudited)
	(in millions)					
Net cash provided by (used in)						
Operating activities	$ 12.7	$ 82.5	$ 186.6	$ 145.9	$ 44.1	$ 24.2
Investing activities	(12.3)	(730.3)	(240.2)	(268.6)	(107.3)	(26.2)
Financing activities	(52.4)	712.5	30.8	111.3	28.9	(3.4)
Net increase (decrease) in cash and cash equivalents	$ (52.0)	$ 64.7	$ (22.8)	$ (11.4)	$ (34.3)	$ (5.4)

In addition, we are currently entitled to all cash distributed by the Partnership. However, the amount of cash flows from the Partnership that we will receive in the future may be limited by a number of factors. The Partnership may enter into its own credit facility or other contracts that limit its ability to make distributions to us. Additionally, in the future the managing general partner of the Partnership will receive a greater allocation of distributions as more cash becomes available for distribution, and consequently we will receive a smaller percentage of quarterly distributions over time. Our rights to distributions will also be adversely affected if the Partnership consummates a public or private equity offering in the future. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest in the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risk Factors Risks Related to the Nitrogen Fertilizer Business The nitrogen fertilizer business may not have sufficient cash to enable it to make quarterly distributions to us following the payment of expenses and fees and the establishment of cash reserves.

Cash Flows Provided by Operating Activities

Comparison of the Three Months Ended March 31, 2008 and the Three Months Ended March 31, 2007

Net cash flows from operating activities for the three months ended March 31, 2008 was $24.2 million. The positive cash flow from operating activities generated over this period was primarily driven by favorable changes in other working capital and other assets and liabilities, partially offset by unfavorable changes in trading working capital over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and, more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the three months ended

March 31, 2008 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of March 31, 2008 (approximately two years and three months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash

Table of Contents

Flow Swap significantly decreased our net income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $20.8 million increase in the payable to swap counterparty. Other sources of cash in other working capital included $16.6 million of deferred revenue related to prepaid fertilizer shipments and a $5.2 increase in accrued income taxes. Trade working capital for the three months ended March 31, 2008 resulted in a use of cash of $67.5 million. For the three months ended March 31, 2008, accounts receivable increased $30.7 million, inventory increased by $31.6 and accounts payable decreased by $5.2 million.

Net cash flows provided by operating activities for the three months ended March 31, 2007 was $44.1 million. The positive cash flow from operating activities during this period was primarily the result of changes in other assets and liabilities offset by unfavorable changes in trade working capital and other working capital. Net income for the period was not indicative of the operating margins for the period. This was the result of the accounting treatment of our derivatives in general and, more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the three months ended March 31, 2007 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of March 31, 2007 (approximately three years and three months years) and the NYMEX crack spread that is the basis for the underlying swaps had increased during the period, the unrealized losses on the Cash Flow Swap significantly decreased our net income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $129.3 million increase in the payable to swap counterparty. Adding to our operating cash flow for the three months ended March 31, 2007 was a $68.0 million source of cash related to a decrease in trade working capital. For the three months ended March 31, 2007, accounts receivable decreased $44.6 million while inventory increased $23.0 million and accounts payable increased $46.4 million. The change in trade working capital was primarily driven by the impact of the refinery turnaround that began in February 2007. The primary use of cash during the period was $41.3 million for deferred income taxes primarily the result of the unrealized loss on the Cash Flow Swap.

Comparison of the Year Ended December 31, 2007, the Year Ended December 31, 2006, the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net cash flows from operating activities for the year ended December 31, 2007 was $145.9 million. The positive cash flow from operating activities generated over this period was primarily driven by favorable changes in other working capital partially offset by unfavorable changes in trade working capital and other assets and liabilities over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the year ended December 31, 2007 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2007 (approximately two years and six months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash Flow Swap significantly decreased our Net Income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $240.9 million increase in the payable to swap counterparty. Other sources of cash from other working capital included $4.8 million from prepaid expenses and other current assets, $27.0 million from other current liabilities and $20.0 million in insurance proceeds. Reducing our operating cash flow for the year ended December 31, 2007 was $42.9 million use of cash related to changes in trade working capital. For the year ended December 31, 2007, accounts receivable increased $17.0 million and inventory increased by $85.0 million resulting in a net use of cash of $102.0 million. These uses of cash due to changes in trade working

capital were partially offset by an increase in accounts payable, or a source of cash, of $59.1 million. Other primary uses of cash during the period include a $105.3 million increase in our insurance receivable related to the flood and a $57.7 million use of cash related to deferred income taxes primarily the result of the unrealized loss on the Cash Flow Swap.

Net cash flows from operating activities for the year ended December 31, 2006 was $186.6 million. The positive cash flow from operating activities generated over this period was primarily driven by our strong operating environment and favorable changes in other assets and liabilities, partially offset by unfavorable changes in trade working capital and other working capital over the period. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Therefore, the net income for the year ended December 31, 2006 included both the realized losses and the unrealized gains on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2006 (approximately three years and six months) and the NYMEX crack spread that is the basis for the underlying swaps had declined, the unrealized gains on the Cash Flow Swap significantly increased our net income over this period. The impact of these unrealized gains on the Cash Flow Swap is apparent in the $147.0 million decrease in the payable to swap counterparty. Reducing our operating cash flow for the year ended December 31, 2006 was a $0.3 million use of cash related to an increase in trade working capital. For the year ended December 31, 2006, accounts receivable decreased approximately $1.9 million while inventory increased $7.2 million and accounts payable increased $5.0 million. Other primary uses of cash during the period include a $5.4 million increase in prepaid expenses and other current assets and a $37.0 million reduction in accrued income taxes. Offsetting these uses of cash was an $86.8 million increase in deferred income taxes primarily the result of the unrealized gain on the Cash Flow Swap and a $4.6 million increase in other current liabilities.

Analysis of cash flows from operating activities for the year ended December 31, 2005 was impacted by the Subsequent Acquisition. See Factors Affecting Comparability. For instance, completion of the Subsequent Acquisition by Successor required a mark up of purchased inventory to fair market value at the closing of the transaction on June 24, 2005. This had the effect of reducing overall cash flow for Successor as it capitalized that portion of the purchase price of the assets into cost of product sold. Therefore, the discussion of cash flows from operations has been broken down into the 174 days ended June 23, 2005 and the 233 days ended December 31, 2005.

Net cash flows from operating activities for the 174 days ended June 23, 2005 was $12.7 million. The positive cash flow generated over this period was primarily driven by income of $52.4 million, offset by a $54.3 million increase in trade working capital. During this period, accounts receivable and inventory increased $11.3 million and $59.0 million, respectively. These uses of cash were primarily the result of our expansion into the rack marketing business, which offered increased accounts receivable credit terms relative to bulk refined product sales, an increase in product sales prices and an increase in overall inventory levels.

Net cash flows provided by operating activities for the 233 days ended December 31, 2005 was $82.5 million. The positive cash flow from operating activities generated over this period was primarily the result of strong operating earnings during the period partially offset by the expensing of a $25.0 million option entered into by Successor for the purpose of hedging certain levels of refined product margins and the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. At the closing of the Subsequent Acquisition, we determined that this option was not economical and we allowed the option to expire worthless and thus resulted in the expensing of the associated premium. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk and Results of Operations Consolidated Results of Operations Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005 (Consolidated). We have determined that the Cash Flow Swap does not

qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net income for the year ended December 31, 2005 included the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap became effective July 1, 2005 and had an original term of approximately five years and the NYMEX crack spread that is the basis for the underlying swaps had improved since the trade date of the Cash Flow Swap on June 16, 2005, the unrealized losses on the Cash Flow Swap significantly reduced our net income over this period. The impact of these unrealized losses on all derivatives, including the Cash Flow Swap, is apparent in the $256.7 million increase in the payable to swap counterparty. Additionally and as a result of the closing of the Subsequent Acquisition, Successor marked up the value of purchased inventory to fair market value at the closing of the transaction on June 24, 2005. This had the effect of reducing overall cash flow for Successor as it capitalized that portion of the purchase price of the assets into cost of product sold. The total impact of this for the 233 days ended December 31, 2005 was $14.3 million. Trade working capital provided $8.0 million in cash during the 233 days ended December 31, 2005 as an increase in accounts receivable was more than offset by decreases in inventory and an increase in accounts payable. Offsetting the sources of cash from operating activities highlighted above was a $98.4 million use of cash related to deferred income taxes and a $4.7 million use of cash related to other long-term assets.

Cash Flows Used In Investing Activities

Comparison of the Three Months Ended March 31, 2008 and the Three Months Ended March 31, 2007

Net cash used in investing activities for the three months ended March 31, 2008 was $26.2 million compared to $107.4 million for the three months ended March 31, 2007. The decrease in investing activities for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was the result of decreased capital expenditures associated with various capital projects that commenced in the first quarter of 2007 in conjunction with the refinery turnaround.

Comparison of the Year Ended December 31, 2007 and the Year Ended December 31, 2006

Net cash used in investing activities for the year ended December 31, 2007 was $268.6 million compared to $240.2 million for the year ended December 31, 2006. The increase in investing activities for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was the result of increased capital expenditures associated with various capital projects in our petroleum business.

Net cash used in investing activities was $12.3 million for the 174 days ended June 23, 2005 and $730.3 million for the 233 days ended December 31, 2005. Investing activities for the combined period ended December 31, 2005 included $685.1 million related to the Subsequent Acquisition. The other primary use of cash for investing activities for the year ended December 31, 2005 was approximately $57.4 million in capital expenditures.

Year Ended December 31, 2006 Compared to the 174 Days Ended June 23, 2005 and the 233 Days Ended December 31, 2005.

Net cash used in investing activities for the year ended December 31, 2006 was $240.2 million compared to $12.3 million for the 174 days ended June 23, 2005 and $730.3 million for the 233 days ended December 31, 2005. Investing activities for the year ended December 31, 2006 was the result of a capital spending increase associated with Tier II fuel compliance and other capital expenditures. Investing activities for the combined period ended December 31, 2005 included $685.1 million related to the Subsequent Acquisition. The other primary use of cash for investing activities for the year ended December 31, 2005 was approximately $57.4 million in capital expenditures.

Cash Flows (Used in) Provided by Financing Activities

Comparison of the Three Months Ended March 31, 2008 and the Three Months Ended March 31, 2007

Net cash used for financing activities for the three months ended March 31, 2008 was $3.4 million as compared to net cash provided by financing activities of $29.0 million for the three months ended March 31, 2007. During the three months ended March 31, 2008, we paid $1.2 million of scheduled principal payments and deferred $2.1 million of initial public offering costs related to CVR Partners, LP. For the three months ended March 31, 2007, the primary source of cash was the result of borrowings drawn on our revolving credit facility.

Comparison of the Year Ended December 31, 2007 and the Year Ended December 31, 2006

Net cash provided by financing activities for the year ended December 31, 2007 was $111.3 million as compared to net cash provided by financing activities of $30.8 million for the year ended December 31, 2006. The primary sources of cash for the year ended December 31, 2007 were obtained through $399.6 million of proceeds associated with our initial public offering. The primary uses of cash for the year ended December 31, 2007 was $335.8 million of long-term debt retirement and $2.5 million in payments of financing costs. The primary sources of cash for the year ended December 31, 2006 were obtained through a refinancing of the Successor s first and second lien credit facilities into a new long term debt credit facility of $1.075 billion, of which $775.0 million was outstanding as of December 31, 2006. The $775.0 million term loan under the credit facility was used to repay approximately $527.7 million in first and second lien debt outstanding, fund $5.5 million in prepayment penalties associated with the second lien credit facility and fund a $250.0 million cash distribution to Coffeyville Acquisition LLC. Other sources of cash included $20.0 million of additional equity contributions into Coffeyville Acquisition LLC, which was subsequently contributed to our operating subsidiaries, and $30.0 million of additional delayed draw term loans issued under the first lien credit facility. During this period, we also paid $1.7 million of scheduled principal payments on the first lien term loans.

For the combined period ended December 31, 2005, net cash provided by financing activities was $660.0 million. The primary sources of cash for the combined periods ended December 31, 2005 related to the funding of Successor s acquisition of the assets on June 24, 2005 in the form of $500.0 million in long-term debt and $227.7 million of equity. Additional equity of $10.0 million was contributed into Coffeyville Acquisition LLC subsequent to the aforementioned acquisition, which was subsequently contributed to our operating subsidiaries, in order to fund a portion of two discretionary capital expenditures at our refining operations. Additional sources of funds during the year ended December 31, 2005 were obtained through the borrowing of $0.2 million in revolving loan proceeds, net of $69.6 million of repayments. Offsetting these sources of cash from financing activities during the year ended December 31, 2005 were $24.6 million in deferred financing costs associated with the first and second lien debt commitments raised by Successor in connection with the Subsequent Acquisition and a $52.2 million cash distribution to Immediate Predecessor prior to the Subsequent Acquisition. See Liquidity and Capital Resources Debt.

Working Capital

Working capital at March 31, 2008, was $21.5 million, consisting of $622.5 million in current assets and $601.0 million in current liabilities. Working capital at December 31, 2007 was $10.7 million, consisting of $570.2 million in current assets and $559.5 million in current liabilities. In addition, we had available borrowing capacity under our revolving credit facility of $112.6 million at March 31, 2008. In the current crude oil price environment, working capital is subject to substantial variability from week-to- week and month-to-month.

Letters of Credit

Our revolving credit facility provides for the issuance of letters of credit. At March 31, 2008, there were $37.4 million of irrevocable letters of credit outstanding, including $5.8 million in support of certain environmental obligators and $31.6 million to secure transportation services for crude oil.

Table of Contents

Capital and Commercial Commitments

In addition to long-term debt, we are required to make payments relating to various types of obligations. The following table summarizes our minimum payments as of March 31, 2008 relating to long-term debt, operating leases, unconditional purchase obligations and other specified capital and commercial commitments for the five-year period following March 31, 2008 and thereafter.

	Payments Due by Period						
	Total	Nine Months Ending 2008	2009	2010	2011	2012	Thereafter
	(in millions)						
Contractual Obligations							
Long-term debt(1)	$ 488.0	$ 3.7	$ 4.8	$ 4.8	$ 4.7	$ 4.7	$ 465.3
Operating leases(2)	8.9	2.8	3.3	1.7	0.9	0.2	
Unconditional purchase obligations(3)	582.3	20.8	28.2	55.8	53.9	51.3	372.3
Environmental liabilities(4)	8.8	2.6	0.7	1.6	0.3	0.3	3.3
Funded letter of credit fees(5)	10.1	3.4	4.5	2.2			
Interest payments(6)	142.0	20.2	26.6	26.3	26.1	25.9	16.9
Total	$ 1,240.1	$ 53.5	$ 68.1	$ 92.4	$ 85.9	$ 82.4	$ 857.8
Other Commercial Commitments							
Standby letters of credit(7)	$ 37.4	$ 37.4	$	$	$	$	$

(1) Long-term debt amortization is based on the contractual terms of our Credit Facility. We may be required to amend our Credit Facility in connection with an offering by the Partnership. As of March 31, 2008, $488.0 million was outstanding under our credit facility. See Liquidity and Capital Resources Debt.

(2) The nitrogen fertilizer business leases various facilities and equipment, primarily railcars, under non-cancelable operating leases for various periods.

(3) The amount includes (1) commitments under several agreements in our petroleum operations related to pipeline usage, petroleum products storage and petroleum transportation and (2) commitments under an electric supply agreement with the city of Coffeyville.

(4) Environmental liabilities represents (1) our estimated payments required by federal and/or state environmental agencies related to closure of hazardous waste management units at our sites in Coffeyville and Phillipsburg, Kansas and (2) our estimated remaining costs to address environmental contamination resulting from a reported release of UAN in 2005 pursuant to the State of Kansas Voluntary Cleanup and Property Redevelopment Program. We also have other environmental liabilities which are not contractual obligations but which would be necessary for our continued operations. See Business Environmental Matters .

(5) This amount represents the total of all fees related to the funded letter of credit issued under our Credit Facility. The funded letter of credit is utilized as credit support for the Cash Flow Swap. See Quantitative and Qualitative

Disclosures About Market Risk Commodity Price Risk .

(6) Interest payments are based on interest rates in effect at April 1, 2008 and assume contractual amortization payments.

(7) Standby letters of credit include $5.8 million of letters of credit issued in connection with environmental liabilities and $31.6 million in letters of credit to secure transportation services for crude oil.

In addition to the amounts described in the above table, we owe J. Aron approximately $123.7 million plus accrued interest ($5.8 million as of June 1, 2008) which will be due August 31, 2008 and approximately $54.0 million which will be due on July 8, 2008 for crude oil we settled or will settle with respect to the quarter ending June 30, 2008 based on June 16, 2008 pricing. Also, if the Partnership does not consummate an initial private or public offering by October 24, 2009, the managing general partner of the Partnership can require us to purchase the managing general partner interest at fair market value until the earlier of October 24, 2012 and the closing of the Partnership s initial offering.

Our ability to make payments on and to refinance our indebtedness, to repay the amounts owed to J. Aron, to purchase the Partnership s managing general partner interest if the Partnership s managing general partner exercises its put right, to fund planned capital expenditures and to satisfy our other capital and commercial commitments will depend on our ability to generate cash flow in the future. This, to a certain extent, is subject to refining spreads, fertilizer margins, receipt of distributions from the Partnership and general economic financial, competitive, legislative, regulatory and other factors that are beyond our control. Our business may not generate sufficient cash flow from operations, and future borrowings may not be available to us under our credit facility (or other credit facilities we may enter into in the future) in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may seek to sell additional assets to fund our liquidity needs but may not be able to do so. We may also need to refinance all or a portion of our indebtedness on or before maturity. Our ability to refinance our indebtedness is also subject to the availability of the credit markets, which in recent periods have been extremely volatile and have experienced significant increases in the cost of financing. We may not be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements as such term is defined within the rules and regulations of the SEC.

Recently Issued Accounting Standards

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *Fair Value Measurements*, which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price) . The standard s provisions for financial assets and financial liabilities, which became effective January 1, 2008, had no material impact on the Company s financial position or results of operations. At March 31, 2008, the only financial assets and financial liabilities that are measured at fair value on a recurring basis are the Company s derivative instruments. See Note 14 to our consolidated financial statements, Fair Value Measurements , included elsewhere in this prospectus.

In February 2008, the FASB issued FASB Staff Position 157-2 which defers the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in an entity s financial statements on a recurring basis (at least annually). The Company will be required to adopt SFAS 157 for these nonfinancial assets and nonfinancial liabilities as of January 1, 2009. Management believes the adoption of SFAS 157 deferral provisions will not have a material impact on the Company s financial position or earnings.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. Under this standard, an entity is required to provide additional information that will assist investors and other users of financial information to more easily understand the effect of the Company s choice to use fair value on its earnings. Further, the entity is required to display the fair value of those assets and liabilities for which the Company has chosen to use fair value on the face of the balance sheet. This standard does not eliminate the disclosure requirements about fair value measurements included in SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*. The provisions of SFAS 159 were effective for CVR as of January 1, 2008. The Company did not elect the fair value option under this standard upon adoption. Therefore, the adoption of SFAS 159 did not impact the Company s consolidated financial statements as of the quarter ended March 31, 2008.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement defines the acquirer as the entity that obtains control of one or more businesses in the business combination, establishes the acquisition date as the date that the acquirer achieves control and requires the acquirer to recognize the assets acquired, liabilities assumed and any non-controlling interest at their fair values as of the acquisition date. This statement also requires that acquisition-related costs of the acquirer be recognized separately from the business combination and will generally be expensed as incurred. CVR Energy will be required to adopt this statement as of January 1, 2009. The impact of adopting SFAS 141(R) will be limited to any future business combinations for which the acquisition date is on or after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 must be applied prospectively. SFAS 160 is effective for CVR beginning January 1, 2009. The Company is currently evaluating the potential impact of the adoption of SFAS 160 on its consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement will change the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, net earnings, and cash flows. The Company will be required to adopt this statement as of January 1, 2009. The adoption of SFAS 161 is not expected to have a material impact on the Company s consolidated financial statements.

The FASB recently issued final FASB Staff Position (FSP) No. APB 14-1 *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement* . The FSP changes the accounting treatment for convertible debt instruments that by their stated terms may be settled in cash upon conversion, including partial cash settlements, unless the embedded conversion option is required to be separately accounted for as a derivative under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Under the FSP, cash settled convertible securities will be separated into their debt and equity components. The FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years and will require issuers of convertible debt that can be settled in cash to record the additional expense incurred. The Company is currently evaluating the FSP in conjunction with its convertible debt offering.

Critical Accounting Policies

We prepare our consolidated financial statements in accordance with GAAP. In order to apply these principles, management must make judgments, assumptions and estimates based on the best available information at the time. Actual results may differ based on the accuracy of the information utilized and subsequent events. Our accounting policies are described in the notes to our audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus. Our critical accounting policies, which are described below, could materially affect the amounts recorded in our financial statements.

Receivables from Insurance

As of March 31, 2008, we have incurred total gross costs of approximately of $154.5 million as a result of the 2007 flood and crude oil discharge. During this period, we have maintained insurance policies that were issued by a variety of insurers and which covered various risks, such as property damage, interruption of our business, environmental cleanup costs, and potential liability to third parties for bodily injury or property damage. Accordingly, as of March 31, 2008, we have recognized receivables of approximately $107.2 million related to these gross costs incurred that we believe are probable of recovery from the insurance carriers under the terms of the respective policies. As of March 31, 2008, we have collected approximately $21.5 million of these receivables.

We are in the process of submitting our claims to, responding to information requests from, and negotiating with the insurers with respect to costs and damages related to the 2007 flood and crude oil discharge. Our property insurers have raised a question as to whether our facilities are principally located in Zone A, which is subject to a $10 million insurance limit for flood or Zone B which is subject to a $300 million insurance limit for flood. We have reached agreement with 32.5% of our property insurers that our facilities are principally located in Zone B. Our remaining property insurers have not, at this time, agreed to this position. In addition, our primary environmental liability insurance carrier has asserted that our pollution liability claims are for cleanup, which is subject to a $10 million sub-limit, rather than property damage, which is covered to the limits of the policy. The excess carrier has reserved its rights under the primary carrier s position. While we will vigorously contest the primary carrier s position, we believe that if that position were upheld, our umbrella and excess Comprehensive General Liability policies would continue to provide coverage for these claims. Although each insurer has reserved its rights under various policy exclusions and limitations and has cited potential coverage defenses, we are vigorously pursuing our insurance recovery claims. We expect that ultimate recovery will be subject to negotiation and, if negotiation is unsuccessful, litigation.

There is inherent uncertainty regarding the ultimate amount or timing of the recovery of the insurance receivable because of the difficulty in projecting the final resolution of our claims. The difference between what we ultimately receive under our insurance policies compared to the receivable we have recorded could be material to our consolidated financial statements.

Long-Lived Assets

We calculate depreciation and amortization on a straight-line basis over the estimated useful lives of the various classes of depreciable assets. When assets are placed in service, we make estimates of what we believe are their reasonable useful lives. CVR accounts for impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. In accordance with SFAS 144, CVR reviews long-lived assets (excluding goodwill, intangible assets with indefinite lives, and deferred tax assets) for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future net cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future net cash flows, an impairment charge is recognized for the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of their carrying value or fair value less cost to sell. No impairment charges were recognized for any of the periods presented.

Derivative Instruments and Fair Value of Financial Instruments

We use futures contracts, options, and forward contracts primarily to reduce exposure to changes in crude oil prices, finished goods product prices and interest rates to provide economic hedges of inventory positions and anticipated interest payments on long-term debt. Although management considers these derivatives economic hedges, the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and accordingly are recorded at fair value in the balance sheet. Changes in the fair value of these derivative instruments are recorded into earnings as a component of other income (expense) in the period of change. The estimated fair values of forward and swap contracts are based on quoted market prices and assumptions for the estimated forward yield curves of related commodities in periods when quoted market prices are unavailable. The Company recorded net

133

gains (losses) from derivative instruments of ($323.7) million, $94.5 million, $(282.0) million and $(47.9) million in gain (loss) on derivatives for the fiscal years ended December 31, 2005, 2006 and 2007 and the three months ended March 31, 2008, respectively.

As of March 31, 2008, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $32.6 million change to the fair value of derivative commodity position and the same change to net income.

Environmental Expenditures

Liabilities related to future remediation of contaminated properties are recognized when the related costs are considered probable and can be reasonably estimated. Estimates of these costs are based upon currently available facts, existing technology, site-specific costs, and currently enacted laws and regulations. In reporting environmental liabilities, no offset is made for potential recoveries. All liabilities are monitored and adjusted as new facts or changes in law or technology occur. Environmental expenditures are capitalized when such costs provide future economic benefits. Changes in laws, regulations or assumptions used in estimating these costs could have a material impact to our financial statements. The amount recorded for environmental obligations (exclusive of estimated obligations associated with the crude oil discharge) at March 31, 2008 totaled $7.7 million, including $2.8 million included in current liabilities. Additionally, at March 31, 2008, $1.0 million was included in current liabilities for estimated future remediation obligations arising from the crude oil discharge. This amount also included estimated obligations to settle third party property damage claims resulting from the crude oil discharge.

Income Taxes

Income tax expense is estimated based on the projected effective tax rate based upon future tax return filings. The amounts anticipated to be reported in those filings may change between the time the financial statements are prepared and the time the tax returns are filed. Further, because tax filings are subject to review by taxing authorities, there is also the risk that a position on a tax return may be challenged by a taxing authority. If the taxing authority is successful in asserting a position different than that taken by us, differences in a tax expense or between current and deferred tax items may arise in future periods. Any of these differences which could have a material impact on our financial statements would be reflected in the financial statements when management considers them probable of occurring and the amount reasonably capable of being estimated.

Valuation allowances reduce deferred tax assets to an amount that will more likely than not be realized. Management s estimates of the realization of deferred tax assets is based on the information available at the time the financial statements are prepared and may include estimates of future income and other assumptions that are inherently uncertain. No valuation allowance is currently recorded, as we expect to realize our deferred tax assets.

Consolidation of Variable Interest Entities

In accordance with FIN No. 46R management has reviewed the terms associated with our interests in the Partnership based upon the partnership agreement. Management has determined that the Partnership is treated as a variable interest entity and as such has evaluated the criteria under FIN 46R to determine that we are the primary beneficiary of the Partnership. FIN 46R requires the primary beneficiary of a variable interest entity s activities to consolidate the VIE. FIN 46R defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and where there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. As the primary beneficiary, we absorb the majority of the expected losses and/or receive a majority of the expected residual returns of the VIE s activities.

We will need to reassess our investment in the Partnership from time to time to determine whether we are the primary beneficiary. If in the future we conclude that we are no longer the primary beneficiary, we will be required to deconsolidate the activities of the Partnership on a going forward basis. The interest would then be recorded using the equity method and the Partnership gross

Table of Contents

revenues, expenses, net income, assets and liabilities as such would not be included in our consolidated financial statements.

Quantitative and Qualitative Disclosures About Market Risk

The risk inherent in our market risk sensitive instruments and positions is the potential loss from adverse changes in commodity prices and interest rates. None of our market risk sensitive instruments are held for trading.

Commodity Price Risk

Our petroleum business, as a manufacturer of refined petroleum products, and the nitrogen fertilizer business, as a manufacturer of nitrogen fertilizer products, all of which are commodities, has exposure to market pricing for products sold in the future. In order to realize value from our processing capacity, a positive spread between the cost of raw materials and the value of finished products must be achieved (i.e., gross margin or crack spread). The physical commodities that comprise our raw materials and finished goods are typically bought and sold at a spot or index price that can be highly variable.

We use a crude oil purchasing intermediary which allows us to take title and price of our crude oil at the refinery, as opposed to the crude origination point, reducing our risk associated with volatile commodity prices by shortening the commodity conversion cycle time. The commodity conversion cycle time refers to the time elapsed between raw material acquisition and the sale of finished goods. In addition, we seek to reduce the variability of commodity price exposure by engaging in hedging strategies and transactions that will serve to protect gross margins as forecasted in the annual operating plan. Accordingly, we use financial derivatives to economically hedge future cash flows (i.e., gross margin or crack spreads) and product inventories. With regard to our hedging activities, we may enter into, or have entered into, derivative instruments which serve to:

- lock in or fix a percentage of the anticipated or planned gross margin in future periods when the derivative market offers commodity spreads that generate positive cash flows;
- hedge the value of inventories in excess of minimum required inventories; and
- hedge the value of inventories held with respect to our rack marketing business.

Further, we intend to engage only in risk mitigating activities directly related to our business.

Basis Risk. The effectiveness of our derivative strategies is dependent upon the correlation of the price index utilized for the hedging activity and the cash or spot price of the physical commodity for which price risk is being mitigated. Basis risk is a term we use to define that relationship. Basis risk can exist due to several factors including time or location differences between the derivative instrument and the underlying physical commodity. Our selection of the appropriate index to utilize in a hedging strategy is a prime consideration in our basis risk exposure.

Examples of our basis risk exposure are as follows:

- Time Basis   In entering into over-the-counter swap agreements, the settlement price of the swap is typically the average price of the underlying commodity for a designated calendar period. This settlement price is based on the assumption that the underlying physical commodity will price ratably over the swap period. If the commodity does not move ratably over the periods then weighted average physical prices will be weighted differently than the swap price as the result of timing.

Location Basis In hedging NYMEX crack spreads, we experience location basis as the settlement of NYMEX refined products (related more to New York Harbor cash markets) which may be different than the prices of refined products in our Group 3 pricing area.

Price and Basis Risk Management Activities. The most significant derivative position we have is our Cash Flow Swap. The Cash Flow Swap, for which the underlying commodity is the crack spread, enabled us to lock in a margin on the spread between the price of crude oil and price of refined products at the execution date of the agreement. We may look for opportunities to reduce the effective position of the Cash Flow Swap by buying either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps. In addition, we may sell forward crack spreads when opportunities exist to lock in a margin.

In the event our inventories exceed our target base level of inventories, we may enter into commodity derivative contracts to manage our price exposure to our inventory positions that are in excess of our base level. Excess inventories are typically the result of plant operations such as a turnaround or other plant maintenance. The commodity derivative contracts are either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps.

To reduce the basis risk between the price of products for Group 3 and that of the NYMEX associated with selling forward derivative contracts for NYMEX crack spreads, we may enter into basis swap positions to lock the price difference. If the difference between the price of products on the NYMEX and Group 3 (or some other price benchmark as we may deem appropriate) is different than the value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product contracted in the swap, thereby completing the locking of our margin. An example of our use of a basis swap is in the winter heating oil season. The risk associated with not hedging the basis when using NYMEX forward contracts to fix future margins is if the crack spread increases based on prices traded on NYMEX while Group 3 pricing remains flat or decreases then we would be in a position to lose money on the derivative position while not earning an offsetting additional margin on the physical position based on the Group 3 pricing.

As of March 31, 2008, a $1.00 change in quoted futures price for the crack spreads described in the first bullet point would result in a $36.2 million change to the fair value of the derivative commodity position and the same change in net income.

Interest Rate Risk

As of March 31, 2008, all of our $488.0 million of outstanding term debt was at floating rates. An increase of 1.0% in the LIBOR rate would result in an increase in our interest expense of approximately $4.9 million per year.

In an effort to mitigate the interest rate risk highlighted above and as required under our then-existing first and second lien credit agreements, we entered into several interest rate swap agreements in 2005. These swap agreements were entered into with counterparties that we believe to be creditworthy. Under the swap agreements, we pay fixed rates and receive floating rates based on the three-month LIBOR rates, with payments calculated on the notional amounts set forth in the table below. The interest rate swaps are settled quarterly and marked to market at each reporting date.

Notional Amount	Effective Date	Termination Date	Fixed Rate
$250.0 million	March 31, 2008	March 30, 2009	4.195%
$180.0 million	March 31, 2009	March 30, 2010	4.195%
$110.0 million	March 31, 2010	June 29, 2010	4.195%

We have determined that these interest rate swaps do not qualify as hedges for hedge accounting purposes. Therefore, changes in the fair value of these interest rate swaps are included in income in the period of change. Net realized and unrealized gains or losses are reflected in the gain (loss) for derivative activities at the end of each period. For the year ended December 31, 2007, we had $4.8 million of realized and unrealized losses on these interest rate swaps. For the three months ended March 31, 2008 and March 31, 2007, we had $5.6 million and $0.6 million of realized and unrealized losses on these interest rate swaps, respectively.

INDUSTRY OVERVIEW

Oil Refining Industry

Oil refining is the process of separating the wide spectrum of hydrocarbons present in crude oil, and in certain processes, modifying the constituent molecular structures, for the purpose of converting them into marketable finished, or refined, petroleum products optimized for specific end uses. Refining is primarily a margin-based business where both the feedstocks (the petroleum products such as crude oil or natural gas liquids that are processed and blended into refined products) and the refined finished products are commodities. It is important for a refinery to maintain high throughput rates (the volume per day processed through the refinery) and capacity utilization given the substantial fixed component in the total operating costs. There are also material variable costs associated with the fuel and by-product components that become increasingly expensive as crude prices increase. The refiner s goal is to achieve highest profitability by maximizing the yields of high value finished products and by minimizing feedstock and operating costs.

According to the Energy Information Administration, or the EIA, as of January 1, 2007, there were 145 oil refineries operating in the United States, with the 15 smallest each having a capacity of 12,500 bpd or less, and the 10 largest having capacities ranging from 306,000 to 562,500 bpd. Refiners typically are structured as part of a fully or partially integrated oil company, or as an independent entity, such as our Company.

Refining Margins

A variety of so called crack spread indicators are used to track the profitability of the refining industry. Among those of most relevance to our refinery are (1) the gasoline crack spread, (2) the heat crack spread, and (3) the 2-1-1 crack spread. The gasoline crack spread is the simple difference in per barrel value between reformulated gasoline (gasoline with compounds or properties which meet the requirements of the reformulated gasoline regulations) in New York Harbor as traded on the New York Mercantile Exchange, or NYMEX, and the NYMEX prompt price of West Texas Intermediate, or WTI, crude oil on any given day. This provides a measure of the profitability when producing gasoline. The heat crack spread is the similar measure of the price of Number 2 heating oil in New York Harbor as traded on the NYMEX, relative to the value of WTI crude which provides a measure of the profitability of producing distillates. The 2-1-1 crack spread is a composite spread that assumes for simplification and comparability purposes that for every two barrels of WTI consumed, a refinery produces one barrel of gasoline and one barrel of heating oil; the spread is based on the NYMEX price and delivery of gasoline and heating oil in New York Harbor. The 2-1-1 crack spread provides a measure of the general profitability of a medium high complexity refinery on the day that the spread is computed. The ability of a crack spread to measure profitability is affected by the absolute crude price.

Our refinery uses a consumed 2-1-1 crack spread to measure its specific daily performance in the market. The consumed 2-1-1 crack spread assumes the same relative production of gasoline and heating oil from crude, so like the NYMEX based 2-1-1 crack spread, it has an inherent inaccuracy because the refinery does not produce exactly two barrels of high valued products for each two barrels of crude oil, and the relative proportions of gasoline to heating oil will vary somewhat from the 1:1 relationship. However, the consumed 2-1-1 crack spread is an economically more accurate measure of performance than the NYMEX based 2-1-1 crack spread since the crude price used represents the price of our actual charged crude slate and is based on the actual sale values in our marketing region, rather than on New York Harbor NYMEX numbers. Average 2-1-1 crack spreads vary from region to region depending on the supply and demand balances of crude oils and refined products and can vary seasonally and from year to year reflecting more macroeconomic factors.

Although refining margins, the difference between the per barrel prices for refined products and the cost of crude oil, can be volatile during short term periods of time due to seasonality of demand, refinery outages, extreme weather conditions and fluctuations in levels of refined product held in storage, longer-term averages have steadily increased over the last 10 years as a result of the improving fundamentals for the refining industry. For example, the NYMEX based 2-1-1 crack spread averaged $3.88 per barrel from 1994 through 1998 compared to $11.02 per barrel from 2004 to March 31, 2008. The following chart shows a rolling average of the NYMEX based 2-1-1 crack spread from 1994 through March 31, 2008:

Source: Platts

There are a number of reasons high crude oil costs have a negative impact on our earnings. Less than 100% of the crude oil we purchase can actually be turned into profitable transportation fuels; the conversion process also produces less valuable byproducts such as pet coke, slurry and sulfur. These byproducts are less valuable than transportation fuels, and their sales prices have not increased in proportion to crude oil prices. Therefore, as the price on crude oil increases our loss on byproduct sales increases, which results in a reduction in earnings. Also, as discussed previously, as crack spreads increase in absolute terms in connection with higher crude prices, the Company realizes increasing losses on the Cash Flow Swap.

Refining Market Trends

The supply and demand fundamentals of the domestic refining industry have improved since the 1990s and are expected to remain favorable as the growth in demand for refined products continues to exceed increases in refining capacity. Over the next two decades, the EIA projects that U.S. demand for refined products will grow at an average of 0.8% per year compared to total domestic refining capacity growth of only 0.3% per year. Substantially all of the projected demand growth is expected to come from the increased consumption of transportation fuels.

High capital costs, historical excess capacity and environmental regulatory requirements have limited the construction of new refineries in the United States over the past 30 years. According to the EIA, domestic refining capacity decreased approximately 6% between January 1981 and January 2007 from 18.6 million bpd to 17.4 million bpd, as more than 175 generally small and unsophisticated refineries that were unable to process heavy crude into a marketable product mix have been shut down, and no new major refinery has been built in the United States. The implementation of the federal Tier II low sulfur fuel regulations is expected to further reduce existing refining capacity.

As reflected within the U.S. Days Forward Supply and the U.S. Mogas Inventory statistics provided by the EIA, the gasoline available for consumption in the United States has declined year after year. This trend is in most part attributable to a steady increase in demand that has not been matched by an equal increase in supply. Although existing refiners are improving their utilization rates, the total number of refiners has declined. As a result, the U.S. has been dependent on imported fuels to meet domestic demand while the global supply which has historically been available for importation has been subject to increasing worldwide demand. With this reduction in days of available supply, we believe the U.S. will occasionally experience periods of little or no supply of gasoline in various markets as the supply and distribution system continues to strain to match available inventory with consumer demand.

In order to meet the increasing demands of the market, U.S. refineries have pursued efficiency measures to improve existing production levels. These efficiency measures and other initiatives, generally known as capacity creep, have raised productive capacity of existing refineries by approximately 1% per year since 1993. According to the EIA, between 1981 and 2004, refinery utilization increased from 69% to 93%. Over the next 25 years, the EIA projects that utilization will remain high relative to historic levels, ranging from 90% to 95% of design capacity.

The price discounts available to refiners of heavy sour crude oil have widened as many refiners have turned to sweeter and lighter crude oils to meet lower sulfur fuel specifications, which has resulted in increasing the surplus of sour and heavy crude oils. As the global economy has improved, worldwide crude oil demand has increased, and OPEC and other producers have tended to incrementally produce more of the sour or heavier crude oil varieties. We believe that the combination of increasing worldwide supplies of lower cost sour and heavy crude oils and increasing demand for sweet and light crude oils will provide a cost advantage to refineries with configurations that are able to process sour crude oils.

We expect refined products that meet new and evolving fuel specifications will account for an increasing share of total fuel demand, which will benefit refiners who are able to efficiently produce these fuels. As part of the Clean Air Act, major metropolitan areas in the United States with air pollution problems must require the sale and use of reformulated gasoline meeting certain environmental standards in their jurisdictions. Boutique fuels, such as low vapor pressure Kansas City gasoline, enable refineries capable of producing such refined products to achieve higher margins.

Due to the ongoing supply and demand imbalance, the United States continues to be a net refined products importer. Imports, largely from northwest Europe and Asia, accounted for over 12%

of total U.S. consumption in 2005. The level of imports generally increases during periods when refined product prices in the United States are materially higher than in Europe and Asia.

Based on the strong fundamentals for the global refining industry, capital investments for refinery expansions and new refineries in international markets have increased during the recent year. However, the competitive threat faced by domestic refiners is limited by U.S. fuel specifications and increasing foreign demand for refined products, particularly for light transportation fuels.

Certain regional markets in the United States, such as the mid-continent region where our refinery is located, do not have the necessary refining capacity to produce a sufficient amount of refined products to meet area demand and therefore rely on pipelines and other modes of transportation for incremental supply from other regions of the United States and globally. The shortage of refining capacity is a factor that results in local refiners serving these markets earning generally higher margins on their product sales than those who have to transport their products to this region over long distances.

Notwithstanding the trends described above, the refining industry is cyclical and volatile and has undergone downturns in the past. See Risk Factors.

Refinery Locations

A refinery s location can have an important impact on its refining margins because location can influence access to feedstocks and efficient distribution. There are five regions in the United States, the Petroleum Administration for Defense Districts (PADDs), that have historically experienced varying levels of refining profitability due to regional market conditions. Refiners located in the U.S. Gulf Coast region operate in a highly competitive market due to the fact that this region (PADD III) accounts for approximately 38% of the total number of U.S. refineries and approximately 48% of the country s refining capacity. PADD I represents the East Coast, PADD IV the Rocky Mountains and PADD V is the West Coast.

Coffeyville operates in the Midwest (PADD II) region of the US. In 2007, demand for gasoline and distillates (primarily diesel fuels, kerosene and jet fuel) exceeded refining production in the mid-continent region, which created a need to import a significant portion of the region s requirement for petroleum products from the U.S. Gulf Coast and other regions. The deficit of local refining capacity benefits local refined product pricing and could generally lead to higher margins for local refiners such as our company.

Table of Contents

Nitrogen Fertilizer Industry

Plant Nutrition and Nitrogen Fertilizers

Commercially produced nitrogen fertilizers provide primary nutrients for plant growth in a form that is readily absorbable. Nitrogen is an essential element for plant growth and vigor and is the most important element for increasing yields in crop plants. Nitrogen and other plant nutrients are found naturally in organic matter and soil materials but are depleted by intensive crop production and harvesting. Replenishing nitrogen through application of commercial fertilizers is the most widely used way of sustaining or increasing crop yields. Two primary sources of plant nutrients are manufactured fertilizers and organic manures. Farmers determine the types, quantity and proportions of fertilizer to apply depending upon crop type, soil and weather conditions, regional farming practices, fertilizer and crop prices and other factors.

Nitrogen, which typically accounts for approximately 60% of worldwide fertilizer consumption in any planting season, is an essential element for most organic compounds in plants as it promotes protein formation and is a major component of chlorophyll, which helps to promote green healthy growth and high yields. There are no substitutes for nitrogen fertilizers in the cultivation of high-yield crops such as corn, which on average requires 100-160 pounds of nitrogen for each acre of plantings. The four principal nitrogen based fertilizer products are:

Ammonia. Ammonia is used in limited quantities as a direct application fertilizer, and is primarily used as a building block for other nitrogen products, including intermediate products for industrial applications and finished fertilizer products. Ammonia, consisting of 82% nitrogen, is stored either as a refrigerated liquid at minus 27 degrees, or under pressure if not refrigerated. It is gaseous at ambient temperatures and is injected into the soil as a gas. The direct application of ammonia requires farmers to make a considerable investment in pressurized storage tanks and injection machinery, and can take place only under a narrow range of ambient conditions.

Urea. Urea is formed by reacting ammonia with CO_2 at high pressure. From the warm urea liquid produced in the first, wet stage of the process, the finished product is mostly produced as a coated, granular solid containing 46% nitrogen and suitable for use in bulk fertilizer blends containing the other two principal fertilizer nutrients, phosphate and potash. We do not produce merchant urea.

Ammonium Nitrate. Ammonium nitrate is another dry, granular form of nitrogen based fertilizer. It is produced by converting ammonia to nitric acid in the presence of a platinum catalyst reaction, then further reacting the nitric acid with additional volumes of ammonia to form ammonium nitrate. We do not produce this product.

Urea Ammonium Nitrate Solution. Urea can be combined with ammonium nitrate solution to make liquid nitrogen fertilizer (urea ammonium nitrate or UAN). These solutions contain 32% nitrogen and are easy to store and transport.

In 2007, we produced approximately 326,662 tons of ammonia, of which approximately 72% was upgraded into approximately 576,888 tons of UAN.

Ammonia Production Technology Advantages of Pet Coke Gasification

Ammonia is produced by reacting gaseous nitrogen with hydrogen at high pressure and temperature in the presence of a catalyst. Traditionally, nearly all hydrogen produced for the manufacture of nitrogen based fertilizers was produced by reforming natural gas at a high temperature and pressure in the presence of water and a catalyst. This process consumes a significant amount of natural gas and as a result production costs increase significantly as natural gas prices increase.

Alternatively, hydrogen for ammonia can also be produced by gasifying pet coke. Pet coke is a coal-like substance that is produced during the petroleum refining process. The pet coke gasification process, which the nitrogen fertilizer business commercially employs at its fertilizer plant, the only such plant in North America, takes advantage of the large cost differential between pet coke and natural gas in current markets. The nitrogen fertilizer plant s pet coke gasification process allows it to use approximately 1% of the natural gas relative to other nitrogen based fertilizer facilities that are heavily dependent upon natural gas and are thus heavily impacted by natural gas price swings. The nitrogen fertilizer business also benefits from the ready availability of pet coke supply from our refinery plant. Pet coke is a refinery by-product which if not used in the fertilizer plant would otherwise be sold as fuel, generating less value to the company.

Fertilizer Consumption Trends

Global demand for fertilizers typically grows at predictable rates and tends to correspond to growth in grain production and pricing. Global fertilizer demand is driven in the long-term primarily by population growth, increases in disposable income and associated improvements in diet. Short-term demand depends on world economic growth rates and factors creating temporary imbalances in supply and demand. These factors include weather patterns, the level of world grain stocks relative to consumption, agricultural commodity prices, energy prices, crop mix, fertilizer application rates, farm income and temporary disruptions in fertilizer trade from government intervention, such as changes in the buying patterns of large countries like China or India. According to the International Fertilizer Industry Association, or IFA, from 1960 to 2005, global fertilizer demand has grown 3.7% annually and global nitrogen demand has grown at a faster rate of 4.8% annually. According to the IFA, during that 45-year period, North American fertilizer demand has grown 2.4% annually with North American nitrogen fertilizer demand growing at a faster rate of 3.3% annually.

According to the United States Department of Agriculture, or USDA, U.S. farmers planted 92.9 million acres of corn in 2007, exceeding the 2006 planted area by 19 percent. This increase was driven in large part by ethanol demand. The actual planted acreage is the highest on record since 1944, when farmers planted 95.5 million acres of corn. Farmers in nearly all states increased their planted corn acreage in 2007. State records were established in Illinois, Indiana, Minnesota and North Dakota, while Iowa led all states in total planted corn acres. A net effect of these additional planted acres was to increase the demand for nitrogen fertilizers by over one million tons. This equates to an annual increase of 3.3 million tons of UAN, or approximately 5 times the nitrogen fertilizer plant s total UAN production. The USDA is forecasting as of March 2008 that total U.S. planted corn acreage in 2008 will decline to 86 million acres. Despite this decrease, Blue Johnson estimates that nitrogen fertilizer consumption by farm users in 2008 will increase by one million tons due to the need to correct for under fertilization of corn in 2007, a forecasted increase in total planted wheat acreage and very strong crop prices. This estimated increase in nitrogen usage translates into an annual increase of 3.3 million tons of UAN, or approximately five times the nitrogen fertilizer business total 2008 estimated UAN production.

The Farm Belt Nitrogen Market

The majority of the nitrogen fertilizer business product shipments target freight advantaged destinations located in the U.S. farm belt. The farm belt refers to the states of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas and Wisconsin. Because shipping ammonia requires refrigerated or pressured containers and UAN is more than 65% water, transportation cost is substantial for ammonia and UAN producers and importers. As a result, locally based fertilizer producers, such as the nitrogen fertilizer business, enjoy a distribution cost advantage over U.S. Gulf Coast ammonia and UAN producers and importers. Southern Plains spot ammonia and corn belt UAN 32 prices averaged $337/ton and $201/ton, respectively, for the

2003 through 2007 period, based on data provided by Blue Johnson. The volumes of ammonia and UAN sold into certain farm belt markets in 2007 are set forth in the table below:

2005-2007 Average U.S. Ammonia and UAN Demand in Selected Mid-continent Areas

State	Ammonia Quantity	UAN 32 Quantity(1)
	(thousand tons per year)	
Texas	2,125	850
Oklahoma	95	200
Kansas	395	690
Missouri	325	230
Iowa	710	900
Nebraska	425	1,150
Minnesota	310	200

(1) UAN 32, which consists of 45% ammonium nitrate, 35% urea and 20% water, contains 32% nitrogen by weight and is the most common grade of UAN sold in the United States. *Source: Blue Johnson*

Fertilizer Pricing Trends

The nitrogen fertilizer industry is cyclical and relatively volatile, reflecting the commodity nature of ammonia and the major finished fertilizer products (e.g., urea). Although domestic industry-wide sales volumes of nitrogen based fertilizers vary little from one fertilizer season to the next due to the need to apply nitrogen every year to maintain crop yields, in the normal course of business industry participants are exposed to fluctuations in supply and demand, which can have significant effects on prices across all participants commodity business areas and products and, in turn, their operating results and profitability. Changes in supply can result from capacity additions or reductions and from changes in inventory levels. Demand for fertilizer products is dependent on demand for crop nutrients by the global agricultural industry, which, in turn, depends on, among other things, weather conditions in particular geographical regions. Periods of high demand, high capacity utilization and increasing operating margins tend to result in new plant investment, higher crop pricing and increased production until supply exceeds demand, followed by periods of declining prices and declining capacity utilization, until the cycle is repeated. Due to dependence of the prevalent nitrogen fertilizer technology on natural gas, the marginal cost and pricing of fertilizer products also tend to exhibit positive correlation with the price of natural gas.

Strong industry fundamentals have led current demand for nitrogen fertilizers to all time highs. US corn inventories at the end of the 2008-2009 fertilizer year are projected to be at 673 million bushels, which is the lowest level since 1995-1996. Corn prices are at record high levels, and corn planting for 2008-2009 is projected to be higher than 2007-2008. Nitrogen fertilizer prices are at record high levels due to increased demand and increasing worldwide natural gas prices. In addition, nitrogen fertilizer prices have been decoupled from their historical correlation with natural gas prices in recent years and increased substantially more than natural gas prices in 2007 and 2008 (based on data provided by Blue Johnson). The quest for healthier lives and better diets in developing countries is a primary driving factor behind the increased global demand for fertilizers. As of June 16, 2008, our order book for UAN is 367,825 tons at an average netback price of $326.56 per ton and 34,898 tons of ammonia at an average netback price of $620.61.

143

Table of Contents

The historical average annual U.S. corn belt ammonia and UAN 32 spot prices as well as natural gas and crude oil prices are detailed in the table below.

Year	Natural Gas ($/million btu)	WTI ($/bbl)	Ammonia ($/ton)	UAN 32 ($/ton)
1990	1.78	24.53	125	90
1991	1.53	21.55	130	97
1992	1.73	20.57	134	95
1993	2.11	18.43	139	102
1994	1.94	17.16	197	108
1995	1.69	18.38	238	132
1996	2.50	22.01	217	129
1997	2.48	20.59	220	116
1998	2.16	14.43	162	96
1999	2.32	19.26	145	86
2000	4.32	30.28	208	115
2001	4.04	25.92	262	144
2002	3.37	26.19	191	108
2003	5.49	31.03	292	141
2004	6.18	41.47	326	170
2005	9.02	56.58	394	210
2006	6.98	66.09	379	196
2007	7.12	72.36	469	290
2008 (through May)	9.77	106.54	681	377

Source: Bloomberg (natural gas and WTI) and Blue Johnson (ammonia and UAN)

Table of Contents

BUSINESS

We are an independent refiner and marketer of high value transportation fuels and, through a limited partnership, a producer of ammonia and UAN fertilizers. We are one of only seven petroleum refiners and marketers in within the mid-continent region (Kansas, Oklahoma, Missouri, Nebraska and Iowa). The nitrogen fertilizer business is the only operation in North America that uses a coke gasification process, and at current natural gas and pet coke prices, the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN fertilizers in North America.

Our petroleum business includes a 115,000 bpd complex full coking medium-sour crude refinery in Coffeyville, Kansas. In addition, our supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma and southwestern Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of approximately 1.2 million barrels and (4) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and to customers at throughput terminals on Magellan Midstream Partners L.P. s refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Partners L.P. and NuStar Energy L.P. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States, served by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude variety in the world capable of being transported by pipeline.

The nitrogen fertilizer business, consists of a nitrogen fertilizer manufacturing facility comprised of (1) a 1,225 ton-per-day ammonia unit, (2) a 2,025 ton-per-day UAN unit and (3) an 84 million standard cubic foot per day gasifier complex. We are currently enjoying unprecedented fertilizer prices which have contributed favorably to our earnings. The nitrogen fertilizer business is the only operation in North America that utilizes a coke gasification process to produce ammonia (based on data provided by Blue Johnson). In 2007, approximately 72% of the ammonia produced by the fertilizer plant was further upgraded to UAN fertilizer (a solution of urea, ammonium nitrate and water used as a fertilizer). By using pet coke (a coal-like substance that is produced during the refining process) instead of natural gas as a primary raw material, at current natural gas and pet coke prices the nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN fertilizers in North America. Furthermore, on average during the last four years, over 75% of the pet coke utilized by the fertilizer plant was produced and supplied to the fertilizer plant as a by-product of our refinery. As such, the nitrogen fertilizer business benefits from high natural gas prices, as fertilizer prices generally increase with natural gas prices, without a directly related change in cost (because pet coke rather than natural gas is used as a primary raw material).

We have two business segments: petroleum and nitrogen fertilizer. We generated combined net sales of $2.4 billion, $3.0 billion and $3.0 billion and operating income of $270.8 million, $281.6 million and $186.6 million for the fiscal years ended December 31, 2005, 2006 and 2007, respectively. Our petroleum business generated $2.3 billion, $2.9 billion and $2.8 billion of our combined net sales, respectively, over these periods, with the nitrogen fertilizer business generating substantially all of the remainder. In addition, during these periods, our petroleum business contributed $199.7 million, $245.6 million and $144.9 million, respectively, of our combined operating income with substantially all of the remainder contributed by the nitrogen fertilizer business. For the three months ended March 31, 2008, we generated combined net sales of $1.22 billion and operating income of $87.4 million. Our petroleum business generated $1.17 billion of our combined net sales and $63.6 million of our combined operating income during this period, with substantially all of the remainder contributed by the nitrogen fertilizer business.

Table of Contents

Our Competitive Strengths

Regional Advantage and Strategic Asset Location. Our refinery is located in the southern portion of the PADD II Group 3 distribution area. Because refined product demand in this area exceeds production, the region has historically required U.S. Gulf Coast imports to meet demand. We estimate that this favorable supply/demand imbalance combined with our lower pipeline transportation cost as compared to the U.S. Gulf Coast refiners has allowed us to generate refining margins, as measured by the 2-1-1 crack spread, that have exceeded U.S. Gulf Coast refining margins by approximately $2.14 per barrel on average for the last four years. The 2-1-1 crack spread is a general industry standard that approximates the per barrel refining margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of heating oil.

In addition, the nitrogen fertilizer business is geographically advantaged to supply nitrogen fertilizer products to markets in Kansas, Missouri, Nebraska, Iowa, Illinois and Texas without incurring intermediate transfer, storage, barge or pipeline freight charges. Because the nitrogen fertilizer business does not incur these costs, this geographic advantage provides it with a distribution cost advantage over competitors not located in the farm belt who transport ammonia and UAN from the U.S. Gulf Coast, based on recent freight rates and pipeline tariffs for U.S. Gulf Coast importers.

Access to and Ability to Process Multiple Crude Oils. Since June 2005 we have significantly expanded the variety of crude grades processed in any given month and have reduced our acquisition cost of crude relative to WTI by approximately $1.50 per barrel in 2006 compared to 2005. While our proximity to the Cushing crude oil trading hub minimizes the likelihood of an interruption to our supply, we intend to further diversify our sources of crude oil. Among other initiatives in this regard, we maintain capacity on the Spearhead pipeline, owned by CCPS Transportation, LLC (which is ultimately owned by Enbridge), which connects Chicago to the Cushing hub. We have also committed to additional pipeline capacity on the proposed Keystone pipeline project currently under development by TransCanada Keystone Pipeline, LP which will provide us with access to incremental oil supplies from Canada. We also own and operate a crude gathering system serving northern Oklahoma, central Kansas and southwestern Nebraska, which allows us to acquire quality crudes at a discount to WTI.

High Quality, Modern Refinery with Solid Track Record. Our refinery s complexity allows us to optimize the yields (the percentage of refined product that is produced from crude and other feedstocks) of higher value transportation fuels (gasoline and distillate), which currently account for approximately 94% of our liquid production output. Complexity is a measure of a refinery s ability to process lower quality crude in an economic manner; greater complexity makes a refinery more profitable. From 1995 through March 31, 2008, we have invested approximately $725 million to modernize our oil refinery and to meet more stringent U.S. environmental, health and safety requirements. As a result, we have achieved significant increases in our refinery crude throughput rate, from an average of less than 90,000 bpd prior to June 2005 to an average of over 102,000 bpd in the second quarter of 2006, over 94,500 bpd for all of 2006 and over 110,000 bpd in the fourth quarter of 2007 with maximum daily rates in excess of 120,000 bpd for the fourth quarter of 2007.

Unique Coke Gasification Fertilizer Plant. The nitrogen fertilizer plant, completed in 2000, is the newest fertilizer facility in North America and the only one of its kind in North America using a pet coke gasification process to produce ammonia. While this facility is unique to North America, gasification technology has been in use for over 50 years in various industries to produce fuel, chemicals and other products from carbon-based source materials. Because it uses significantly less natural gas in the manufacture of ammonia than other domestic nitrogen fertilizer plants, with the currently high price of natural gas the nitrogen fertilizer business feedstock cost per ton for ammonia is considerably lower than that of its natural gas-based fertilizer plant competitors. We estimate that the facility s production cost advantage over U.S. Gulf Coast ammonia producers is sustainable at natural gas prices as low as $2.50 per MMBtu (at June 16, 2008, the price of natural gas was $12.93 per MMBtu).

146

Table of Contents

Near Term Internal Expansion Opportunities. Since June 2005, we have identified and developed several significant capital improvements primarily aimed at (1) expanding refinery capacity, (2) enhancing operating reliability and flexibility, (3) complying with more stringent environmental, health and safety standards and (4) improving our ability to process heavy sour crude feedstock varieties. With the substantial completion of approximately $522 million of significant capital improvements (including $170 million in expenditures for our refinery expansion project, excluding $3.7 million in related capitalized interest), we expect to significantly enhance the profitability of our refinery during periods of high crack spreads while enabling the refinery to operate more profitably at lower crack spreads than is currently possible. The spare gasifier at the nitrogen fertilizer plant was expanded in 2006, increasing ammonia production by 6,500 tons per year. In addition, the nitrogen fertilizer plant is moving forward with an approximately $120 million fertilizer plant expansion, of which approximately $11 million was incurred as of March 31, 2008. It is estimated that this expansion will increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium-priced UAN by approximately 50%. Management currently expects to complete this expansion in July 2010.

Experienced Management Team. In conjunction with the acquisition of our business in June 2005 by funds affiliated with Goldman, Sachs & Co. and Kelso & Company, L.P., or the Goldman Sachs Funds and the Kelso Funds, a new senior management team was formed that combined selected members of existing management with experienced new members. Our senior management team averages over 28 years of refining and fertilizer industry experience and, in coordination with our broader management team, has increased our operating income and stockholder value since June 2005.

Mr. John J. Lipinski, our Chief Executive Officer, has over 36 years of experience in the refining and chemicals industries, and prior to joining us in connection with the acquisition of Coffeyville Resources in June 2005, was in charge of a 550,000 bpd refining system and a multi-plant fertilizer system. Mr. Stanley A. Riemann, our Chief Operating Officer, has over 34 years of experience, and prior to joining us in March 2004, was in charge of one of the largest fertilizer manufacturing systems in the United States. Mr. James T. Rens, our Chief Financial Officer, has over 19 years of experience in the energy and fertilizer industries, and prior to joining us in March 2004, was the chief financial officer of two fertilizer manufacturing companies.

Our Business Strategy

The primary business objectives for our refinery business are to increase value for our stockholders and to maintain our position as an independent refiner and marketer of refined fuels in our markets by maximizing the throughput and efficiency of our petroleum refining assets. In addition, management s business objectives on behalf of the Partnership are to increase value for our stockholders and maximize the production and efficiency of the nitrogen fertilizer facilities. We intend to accomplish these objectives through the following strategies:

Pursuing Organic Expansion Opportunities. We continually evaluate opportunities to expand our existing asset base and consider capital projects that accentuate our core competitiveness in petroleum refining. We are also evaluating projects that will improve our ability to process heavy crude oil feedstocks and to increase our overall operating flexibility with respect to crude oil slates. In addition, management also continually evaluates capital projects that are intended to enhance the Partnership s competitiveness in nitrogen fertilizer manufacturing.

Increasing the Profitability of Our Existing Assets. We strive to improve our operating efficiency and to reduce our costs by controlling our cost structure. We intend to make investments to improve the efficiency of our operations and pursue cost saving initiatives. We have recently completed the greenfield construction of a new continuous catalytic reformer. This project is expected to increase the profitability of our petroleum business through increased refined product yields and the elimination of scheduled downtime associated with the reformer that was replaced. In addition, this project reduces the dependence of our refinery on hydrogen supplied by the fertilizer facility, thereby

Table of Contents

allowing the nitrogen fertilizer business to generate higher margins by using the hydrogen to produce ammonia and UAN. The nitrogen fertilizer business expects, over time, to convert 100% of its production to higher-margin UAN.

Seeking Strategic Acquisitions. We intend to consider strategic acquisitions within the energy industry that are beneficial to our shareholders. We will seek acquisition opportunities in our existing areas of operation that have the potential for operational efficiencies. We may also examine opportunities in the energy industry outside of our existing areas of operation and in new geographic regions. In addition, working on behalf of the Partnership, management may pursue strategic and accretive acquisitions within the fertilizer industry, including opportunities in different geographic regions. We have no agreements or understandings with respect to any acquisitions at the present time.

Pursuing Opportunities to Maximize the Value of the Nitrogen Fertilizer Business. Our management, acting on behalf of the Partnership, will continually evaluate opportunities that are intended to enable the Partnership to grow its distributable cash flow. Management s strategies specifically related to the growth opportunities of the Partnership include the following:

> ***Expanding UAN Production.*** The nitrogen fertilizer business is moving forward with an approximately $120 million nitrogen fertilizer plant expansion, of which approximately $11 million was incurred as of March 31, 2008. This expansion is expected to permit the nitrogen fertilizer business to increase its UAN production and to result in its UAN manufacturing facility consuming substantially all of its net ammonia production. This should increase the nitrogen fertilizer plant s margins because UAN has historically been a higher margin product than ammonia. The UAN expansion is expected to be complete in July 2010 and it is estimated that it will result in an approximately 50% increase in the nitrogen fertilizer business annual UAN production. The company has also begun to acquire or lease offsite UAN storage facilities and continues to expand this program.
>
> ***Executing Several Efficiency-Based and Other Projects.*** The nitrogen fertilizer business is currently engaged in several efficiency-based and other projects in order to reduce overall operating costs, incrementally increase its ammonia production and utilize byproducts to generate revenue. For example, by redesigning the system that segregates carbon dioxide, or CO_2, during the gasification process, the nitrogen fertilizer business estimates that it will be able to produce approximately 25 tons per day of incremental ammonia, worth approximately $6 million per year at current market prices. The nitrogen fertilizer business estimates that this project will cost approximately $7 million (of which none has yet been incurred) and will be completed in 2010.
>
> ***Evaluating Construction of a Third Gasifier Unit and a New Ammonia Unit and UAN Unit at the Nitrogen Fertilizer Plant.*** The nitrogen fertilizer business has engaged a major engineering firm to help it evaluate the construction and operation of an additional gasifier unit to produce a synthesis gas from pet coke. It is expected that the addition of a third gasifier unit, together with additional ammonia and UAN units, to the nitrogen fertilizer business operations could result, on a long-term basis, in an increase in UAN production of approximately 75,000 tons per month. This project is in its earliest stages of review and is still subject to numerous levels of internal analysis.

Other opportunities our management may consider on behalf of the Partnership in the event that its managing general partner proceeds with an initial offering include acquiring certain of our petroleum business ancillary assets and providing incremental pipeline transportation and storage infrastructure services to our petroleum business. There are currently no agreements or understandings in place with respect to any such acquisitions or opportunities, and there can be no assurance that the Partnership would be able to operate any of these assets or businesses profitably.

Table of Contents

Our History

Our business was founded in 1906 by The National Refining Company, which at the time was the largest independent oil refiner in the United States. In 1944 the Coffeyville refinery was purchased by the Cooperative Refinery Association, a subsidiary of a parent company that in 1966 renamed itself Farmland Industries, Inc. Our refinery assets and the nitrogen fertilizer plant were operated as a small component of Farmland Industries, Inc., an agricultural cooperative, until March 3, 2004. Farmland filed for bankruptcy protection on May 31, 2002.

Coffeyville Resources, LLC, a subsidiary of Coffeyville Group Holdings, LLC, won the bankruptcy court auction for Farmland s petroleum business and a nitrogen fertilizer plant and completed the purchase of these assets on March 3, 2004. On October 8, 2004, Coffeyville Group Holdings, LLC, through two of its wholly owned subsidiaries, Coffeyville Refining & Marketing, Inc. and Coffeyville Nitrogen Fertilizers, Inc., acquired an interest in Judith Leiber business, a designer handbag business, through an investment in CLJV Holdings, LLC (CLJV), a joint venture with The Leiber Group, Inc., whose majority stockholder was also the majority stockholder of Coffeyville Group Holdings, LLC. On June 23, 2005, the entire interest in the Judith Leiber business held by CLJV was returned to The Leiber Group, Inc. in exchange for all of its ownership interest in CLJV, resulting in a complete separation of the Immediate Predecessor and the Judith Leiber business.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC, which was formed in Delaware on May 13, 2005, acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. With the exception of crude oil, heating oil and gasoline option agreements entered into with J. Aron as of May 16, 2005, Coffeyville Acquisition LLC had no operations from its inception until the acquisition on June 24, 2005.

We were formed in Delaware in September 2006 as a wholly owned subsidiary of Coffeyville Acquisition LLC in order to complete the initial public offering of the businesses acquired by Coffeyville Acquisition, LLC from Coffeyville Group Holdings LLC. We completed our initial public offering on October 26, 2007. At that time, we transferred the nitrogen fertilizer business to CVR Partners, LP, a limited partnership we formed in June 2007. As consideration for the transfer, we received 30,303,000 special GP units and 30,333 special LP units in the Partnership, and the Partnership s managing general partner, which at that time was our indirect wholly-owned subsidiary, received the managing general partner interest and the IDRs. Immediately prior to the consummation of our initial public offering, we sold the managing general partner, together with the IDRs, to Coffeyville Acquisition III LLC, an entity owned by the Goldman Sachs Funds, the Kelso Funds and certain members of CVR Energy s senior management team, for its fair market value on the date of sale.

Petroleum Business

Asset Description

We operate one of the seven refineries located within the mid-continent region (Kansas, Oklahoma, Missouri, Nebraska and Iowa). The Company s complex cracking and coking medium-sour oil refinery has a maximum capacity of 123,500 bpd of petroleum products, which accounts for approximately 17% of the region s output. The facility is situated on approximately 440 acres in southeastern Kansas, approximately 100 miles from Cushing, Oklahoma, a major crude oil trading and storage hub.

The refinery is a complex facility. Complexity is a measure of a refinery s ability to process lower quality crude in an economic manner. It is also a measure of a refinery s ability to convert lower cost, more abundant heavier and sour crudes into greater volumes of higher valued refined products such as gasoline and distillate, thereby providing a competitive advantage over less complex refineries. We have a modified Solomon complexity score of approximately

12.1, up from 10.0 in June 2005. Modified Solomon complexity is a standard industry measure of a refinery s ability to process less-

Table of Contents

expensive feedstock, such as heavier and higher-sulfur content crude oils, into value-added products. Modified Solomon complexity is the weighted average of the Solomon complexity factors for each operating unit multiplied by the throughput of each refinery unit, divided by the crude capacity of the refinery. For the year ended December 31, 2007, our refinery s product yield included gasoline (mainly regular unleaded) (45%), diesel fuel (mainly ultra low sulfur diesel) (42%), and coke and other refined products such as NGL (propane, butane), slurry, reformer feeds, sulfur, gas oil and produced fuel (13%).

The refinery consists of two crude units and two vacuum units. A vacuum unit is a secondary unit which processes crude oil by separating product from the crude unit according to boiling point under high heat and low pressure to recover various hydrocarbons. The availability of more than one crude and vacuum unit creates redundancy in the refinery system and enables us to continue to run the refinery even if one of these units were to shut down for scheduled or unscheduled plant maintenance and upgrades. However, the maximum combined capacity of the crude units is limited by the overall downstream capacity of the vacuum units and other units.

Our petroleum business also includes the following auxiliary operating assets:

Crude Oil Gathering System. We own and operate a 25,000 bpd capacity crude oil gathering system serving central Kansas, northern Oklahoma and southwestern Nebraska. The system has field offices in Bartlesville, Oklahoma and Plainville and Winfield, Kansas. The system is comprised of over 300 miles of feeder and trunk pipelines, 43 trucks, and associated storage facilities for gathering light, sweet Kansas, Nebraska and Oklahoma crude oils purchased from independent crude producers. We also lease a section of a pipeline from Magellan Pipeline Company, L.P.

Phillipsburg Terminal. We own storage and terminalling facilities for asphalt and refined fuels at Phillipsburg, Kansas. Our asphalt storage and terminalling facilities are used to receive, store and redeliver asphalt for another oil company for a fee pursuant to an asphalt services agreement. We also collect fees for refined products we store for another oil company.

Pipelines. We own a 145,000 bpd proprietary pipeline system that transports crude oil from Caney, Kansas to our refinery. Crude oils sourced outside of our proprietary gathering system are delivered by common carrier pipelines into various terminals in Cushing, Oklahoma, where they are blended and then delivered to Caney, Kansas via a pipeline owned by Plains All American L.P. We also own associated crude oil storage tanks with a capacity of approximately 1.2 million barrels located outside our refinery.

Rack Marketing Division. We own a rack marketing division which supplies product through tanker trucks directly to customers located in close geographic proximity to our refinery and Phillipsburg terminal and to customers at throughput terminals on Magellan Midstream Partners L.P. s refined products distribution systems.

Feedstocks Supply

Our refinery has the capability to process blends of a variety of crudes ranging from heavy sour to light sweet crudes. Currently, our refinery processes crude from a broad array of sources. We purchase foreign crudes from Latin America, South America, West Africa, the Middle East, the North Sea and Canada. We purchase domestic crudes from Kansas, Oklahoma, Nebraska, Texas, and offshore deepwater Gulf of Mexico production. While crude oil has historically constituted over 85% of our feedstock inputs during the last five years, other feedstock inputs include isobutane, normal butane, natural gas, alky feed, gas oil and vacuum tower bottoms.

Crude is supplied to our refinery through our wholly owned gathering system and by pipeline. Our crude gathering system was expanded in 2006 and currently supplies in excess of 21,000 bpd of crude to the refinery (approximately 20% of total supply). Locally produced crudes are delivered to the refinery at a discount to WTI and are of similar quality to WTI. These lighter sweet crudes allow us to blend higher percentages of low cost crudes such as heavy sour Canadian while maintaining our target medium sour blend with an API gravity of 28-36 degrees and 0.9-1.2% sulfur. Crude oils sourced outside of our proprietary gathering system are delivered to Cushing, Oklahoma by various pipelines including Seaway, Basin and Spearhead and subsequently to Coffeyville via Plains pipeline and our own 145,000 bpd proprietary pipeline system.

For the year ended December 31, 2007, our crude oil supply blend was comprised of approximately 65% light sweet crude oil, 12% heavy sour crude oil and 23% medium/light sour crude oil. The light sweet crude oil includes our locally gathered crude oil. For the three months ended March 31, 2008, our crude oil supply blend was comprised of approximately 68% of light sweet crude oil, 14% heavy sour crude oil and 18% medium/light sour crude oil.

We purchase most of our crude oil requirements outside of our proprietary gathering system under a credit intermediation agreement with J. Aron. The credit intermediation agreement helps us reduce our inventory position and mitigate crude pricing risk. Once we identify cargos of crude oil and pricing terms that meet our requirements, we notify J. Aron which then provides, for a fee, credit, transportation and other logistical services for delivery of the crude to the crude oil tank farm. Generally, we select crude oil approximately 30 to 45 days in advance of the time the related refined products are to be marketed, except for Canadian and West African crude purchases which require an additional 30 days of lead time due to transit considerations.

Distribution, Sales and Marketing

We focus our petroleum products marketing efforts in the central mid-continent and Rocky Mountain areas because of their relative proximity to our oil refinery and their pipeline access. Since June 2005, we have significantly expanded our rack sales. Rack sales are sales made using tanker trucks via either a proprietary or third party terminal facility designed for truck loading. In the year ended December 31, 2007, approximately 23% of the refinery s products were sold through the rack system directly to retail and wholesale customers while the remaining 77% was sold through pipelines via bulk spot and term contracts. We make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise and NuStar.

We are able to distribute gasoline, diesel fuel, and natural gas liquids produced at the refinery either into the Magellan or Enterprise pipelines and further on through NuStar and other Magellan systems or via the trucking system. The Magellan #2 and #3 pipelines (with capacity of 81,000 bpd and 32,000 bpd, respectively) are connected directly to the refinery and transport products to Kansas City and other northern cities. The NuStar and Magellan (Mountain) pipelines are accessible via the Enterprise outbound line (with capacity of 12,000 bpd) or through the Magellan system at El Dorado, Kansas. Our fuels loading rack at our refinery has a maximum delivery capability of 40,000 bpd of finished gasoline and diesel fuels.

The following map depicts part of the Magellan pipeline, which the oil refinery uses for the majority of its distribution.

Source: Magellan Midstream Partners, L.P.

Customers

Customers for our petroleum products include other refiners, convenience store companies, railroads and farm cooperatives. We have bulk term contracts in place with many of these customers, which typically extend from a few months to one year in length. For the year ended December 31, 2007, QuikTrip Corporation accounted for 11.6% of our petroleum business sales and 64.3% of our petroleum sales were made to our 10 largest customers. For the three months ended March 31, 2008, QuikTrip Corporation accounted for 14.8% of our petroleum business sales and 66.1% of our petroleum sales were made to our 10 largest customers.

Competition

Our oil refinery in Coffeyville, Kansas ranks second in processing capacity and fifth in refinery complexity, among the seven mid-continent fuels refineries. The following table presents certain information about us and the six other major mid-continent fuel oil refineries with which we compete:

Company	Location	Crude Capacity (Barrels per Calendar Day)	Solomon Complexity Index
ConocoPhillips	Ponca City, OK	187,000	13.7
CVR Energy	Coffeyville, KS	115,000	12.1
Frontier Oil	El Dorado, KS	110,000	13.0
Valero	Ardmore, OK	91,500	11.2
NCRA	McPherson, KS	82,700	13.1
Sinclair	Tulsa, OK	70,000	6.2
Gary Williams Energy	Wynnewood, OK	52,500	8.5
Mid-continent Total:		708,700	

Source: Oil and Gas Journal. A Sunoco refinery located in Tulsa, Oklahoma was excluded from this table because it is not a stand-alone fuels refinery. The Solomon Complexity Index of each of these facilities has been calculated based on data from the Oil and Gas Journal together with Company estimates and assumptions.

We compete with our competitors primarily on the basis of price, reliability of supply, availability of multiple grades of products and location. The principal competitive factors affecting our refining operations are costs of crude oil and other feedstock costs, refinery complexity (a measure of a refinery s ability to convert lower cost heavy and sour crudes into greater volumes of higher valued refined products such as gasoline), refinery efficiency, refinery product mix and product distribution and transportation costs. The location of our refinery provides us with a reliable supply of crude oil and a transportation cost advantage over our competitors.

Our competitors include trading companies such as SemFuel, L.P., Western Petroleum, Center Oil, Tauber Oil Company, Morgan Stanley and others. In addition to competing refineries located in the mid-continent United States, our oil refinery also competes with other refineries located outside the region that are linked to the mid-continent market through an extensive product pipeline system. These competitors include refineries located near the U.S. Gulf Coast and the Texas Panhandle region.

Our refinery competition also includes branded, integrated and independent oil refining companies such as BP, Shell, ConocoPhillips, Valero, Sunoco and Citgo, whose strengths include their size and access to capital. Their branded stations give them a stable outlet for refinery production although the branded strategy requires more working capital and a much more expensive marketing organization.

Seasonality

Our petroleum business experiences seasonal effects as demand for gasoline products is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic and road construction work. Demand for diesel fuel during the winter months also decreases due to agricultural work declines during the winter months. As a result, our results of operations for the first and fourth calendar quarters are generally lower than for those for the second and third calendar quarters. In addition, unseasonably cool weather in the summer months and/or unseasonably warm weather in the winter months in the markets in which we sell our petroleum products can vary demand for gasoline and diesel fuel.

Table of Contents

Nitrogen Fertilizer Business

The nitrogen fertilizer business operates the only nitrogen fertilizer plant in North America that utilizes a coke gasification process to generate hydrogen feedstock that is further converted to ammonia for the production of nitrogen fertilizers. The nitrogen fertilizer business is also moving forward with an $120 million fertilizer plant expansion, of which approximately $11 million was incurred as of March 31, 2008, which we estimate could increase the facility s capacity to upgrade ammonia into premium priced UAN by 50% and which we expect to be completed in June 2010.

The facility uses a gasification process licensed from an affiliate of The General Electric Company, or General Electric, to convert pet coke to high purity hydrogen for subsequent conversion to ammonia. It uses between 975 to 1,075 tons per day of pet coke from the refinery and another 260 to 310 tons per day from unaffiliated, third-party sources such as other Midwestern refineries or pet coke brokers and converts it all to approximately 1,200 tons per day of ammonia. The fertilizer plant has demonstrated consistent levels of production at levels close to full capacity and has the following advantages compared to competing natural gas-based facilities:

Significantly Lower Cost Position. Our nitrogen fertilizer plant s pet coke gasification process uses approximately 1% of the natural gas used by other nitrogen-based fertilizer facilities that are heavily dependent upon natural gas and are thus heavily impacted by natural gas price swings. Because the nitrogen fertilizer plant uses pet coke, we have a significant cost advantage over other North American natural gas-based fertilizer producers. This cost advantage is sustainable at natural gas prices as low as $2.50 per MMBtu. Natural gas sold at an average price of $7.12 per MMBtu in the United States in 2007. Average yearly natural gas prices have exceeded $2.50 per MMBtu since 2000, although average prices were lower in prior years. See Industry Overview Fertilizer Pricing Trends . Natural gas prices are cyclical and volatile and may decline at any time. See Risk Factors Risks Related to the Nitrogen Fertilizer Business Natural gas prices affect the price of the nitrogen fertilizers that the nitrogen fertilizer business sells. Any decline in natural gas prices could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions . CVR Energy s adjacent refinery has supplied on average more than 75% of our pet coke needs during the last four years.

Strategic Location with Transportation Advantage. The nitrogen fertilizer business believes that selling products to customers in close proximity to the UAN plant and reducing transportation costs are keys to maintaining its profitability. Due to the plant s favorable location relative to end users and high product demand relative to production volume all of the product shipments are targeted to freight advantaged destinations located in the U.S. farm belt. The available ammonia production at the nitrogen fertilizer plant is small and easily sold into truck and rail delivery points. The products leave the plant either in trucks for direct shipment to customers or in railcars for principally Union Pacific Railroad destinations. The nitrogen fertilizer business does not incur any intermediate transfer, storage, barge freight or pipeline freight charges. Consequently, because these costs are not incurred, we estimate that the plant enjoys a distribution cost advantage over those competitors who are U.S. Gulf Coast ammonia and UAN importers, assuming in each case freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect.

On-Stream Factor. The on-stream factor is a measure of how long the units comprising our nitrogen fertilizer facility have been operational over a given period. We expect that efficiency of the nitrogen fertilizer plant will continue to improve with operator training, replacement of unreliable equipment, and reduced dependence on contract maintenance.

	Year Ended December 31,				
	2003	**2004(1)**	**2005**	**2006(1)**	**2007(1)**

Gasifier	90.1%	92.4%	98.1%	92.5%	90.0%
Ammonia	89.6%	79.9%	96.7%	89.3%	87.7%
UAN	81.6%	83.3%	94.3%	88.9%	78.7%

(1) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period. Excluding the impact of turnarounds at the nitrogen fertilizer facility in the third quarter of 2004 and 2006, (i) the on-stream factors in 2004 would have been 95.6% for gasifier, 83.1% for ammonia and 86.7% for UAN, and (ii) the on-stream factors for the year ended December 31, 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN. Excluding the impact of the flood during the weekend of June 30, 2007, the on-stream factors for the year ended December 31, 2007 would have been 94.6% for gasifier, 92.4% for ammonia and 83.9% for UAN.

Raw Material Supply

The nitrogen fertilizer facility s primary input is pet coke. During the past four years, more than 75% of the nitrogen fertilizer facility s pet coke requirements on average were supplied by our adjacent oil refinery. Historically the nitrogen fertilizer business has obtained the remainder of its pet coke from third parties such as other midwestern refineries or pet coke brokers at spot prices. If necessary, the gasifier can also operate on low grade coal as an alternative, which provides an additional raw material source. There are significant supplies of low grade coal within a 60-mile radius of the nitrogen fertilizer plant.

Pet coke is produced as a by-product of our refinery s coker unit process, which is one step in refining crude oil into gasoline, diesel and jet fuel. In order to refine heavy or sour crude oil, which is lower in cost and more prevalent than higher quality crude, refiners use coker units, which help to reduce the sulfur content in fuels refined from heavy or sour crude oil. In North America, the shift from refining dwindling reserves of sweet crude oil to more readily available heavy and sour crude (which can be obtained from, among other places, the Canadian oil sands) will result in increased pet coke production. With $26.6 billion in coker unit projects planned at North American refineries as of November 2007, pet coke production is expected to increase significantly in the future.

The nitrogen fertilizer plant is located in Coffeyville, Kansas, which is part of the Midwest coke market. The Midwest coke market is not subject to the same level of pet coke price variability as is the U.S. Gulf Coast coke market, due mainly to more stable transportation costs. Transportation costs have gone up substantially in both the Atlantic and Pacific sectors. Given the fact that the majority of the nitrogen fertilizer business suppliers are located in the Midwest, its geographic location gives it (and its similarly located competitors) a significant freight cost advantage over its U.S. Gulf Coast market competitors. The Midwest Green Coke (Chicago Area, FOB Source) annual average price over the last three years has ranged from $24.50 per ton to $27.00. The U.S. Gulf Coast market annual average price during the same period has ranged from $21.29 per ton to $49.83. Furthermore, Sinclair Tulsa Refining, located in Oklahoma, has announced a coker expansion project, and Frontier in El Dorado, Kansas has a coker expansion project under construction. These new refineries should help to further stabilize the Midwest coke market.

The Linde Group owns, operates, and maintains the air separation plant that provides contract volumes of oxygen, nitrogen, and compressed dry air to the gasifier for a monthly fee. The nitrogen fertilizer business provides and pays for all utilities required for operation of the air separation plant. The air separation plant has not experienced any long-term operating problems. The nitrogen fertilizer plant is covered for business interruption insurance for up to $25.0 million in case of any interruption in the supply of oxygen from Linde from a covered peril. The agreement with Linde expires in 2020. The agreement also provides that if our requirements for liquid or gaseous oxygen, liquid or gaseous nitrogen or clean dry air exceed specified instantaneous flow rates by at least 10%, we can solicit bids from Linde and third parties to supply our incremental product needs. We are required to provide notice to Linde of the approximate quantity of excess product that we will need and the approximate date by which we will need it; we and Linde will then jointly develop a request for proposal for soliciting bids from third parties and Linde. The bidding procedures may be limited under specified circumstances.

Table of Contents

The nitrogen fertilizer business imports start-up steam for the fertilizer plant from our adjacent oil refinery, and then exports steam back to the oil refinery once all of its units are in service. Monthly charges and credits are booked with steam valued at the gas price for the month. We have entered into a feedstock and shared services agreement with the Partnership which regulates, among other things, the import and export of start-up steam between the refinery and the nitrogen fertilizer plant.

Production Process

The nitrogen fertilizer plant was built in 2000 with two separate gasifiers to provide reliability. It uses a gasification process licensed from General Electric to convert pet coke into high purity hydrogen for subsequent conversion into ammonia. Following a turnaround completed in the second quarter of 2006, the plant is capable of processing approximately 1,300 tons per day of pet coke from the oil refinery and third-party sources and converting it into approximately 1,200 tons per day of ammonia. A majority of the ammonia is converted to approximately 2,000 tons per day of UAN. Typically 0.41 tons of ammonia are required to produce one ton of UAN.

Pet coke is first ground and blended with water and a fluxant (a mixture of fly ash and sand) to form a slurry that is then pumped into the partial oxidation gasifier. The slurry is then contacted with oxygen from an air separation unit, or ASU. Partial oxidation reactions take place and the synthesis gas, or syngas, consisting predominantly of hydrogen and carbon monoxide, is formed. The mineral residue from the slurry is a molten slag (a glasslike substance containing the metal impurities originally present in coke) and flows along with the syngas into a quench chamber. The syngas and slag are rapidly cooled and the syngas is separated from the slag.

Slag becomes a by-product of the process. The syngas is scrubbed and saturated with moisture. The syngas next flows through a shift unit where the carbon monoxide in the syngas is reacted with the moisture to form hydrogen and carbon dioxide. The heat from this reaction generates saturated steam. This steam is combined with steam produced in the ammonia unit and the excess steam not consumed by the process is sent to the adjacent oil refinery.

After additional heat recovery, the high-pressure syngas is cooled and processed in the acid gas removal, or AGR, unit. The syngas is then fed to a pressure swing absorption, or PSA, unit, where the remaining impurities are extracted. The PSA unit reduces residual carbon monoxide and carbon dioxide levels to trace levels, and the moisture-free, high-purity hydrogen is sent directly to the ammonia synthesis loop.

The hydrogen is reacted with nitrogen from the ASU in the ammonia unit to form the ammonia product. A portion of the ammonia is converted to UAN.

Table of Contents

The following is an illustrative Nitrogen Fertilizer Plant Process Flow Chart:

The nitrogen fertilizer business schedules and provides routine maintenance to its critical equipment using its own maintenance technicians. Pursuant to a Technical Services Agreement with General Electric, which licenses the gasification technology to the nitrogen fertilizer business, General Electric experts provide technical advice and technological updates from their ongoing research as well as other licensees operating experiences.

The pet coke gasification process is licensed from General Electric pursuant to a license agreement that was fully paid up as of June 1, 2007. The license grants the nitrogen fertilizer business perpetual rights to use the pet coke gasification process on specified terms and conditions. The license is important because it allows the nitrogen fertilizer facility to operate at a low cost compared to facilities which rely on natural gas.

Distribution, Sales and Marketing

The primary geographic markets for the fertilizer products are Kansas, Missouri, Nebraska, Iowa, Illinois, Colorado and Texas. Ammonia products are marketed to industrial and agricultural customers and UAN products are marketed to agricultural customers. The direct application agricultural demand from the nitrogen fertilizer plant occurs in three main use periods. The summer wheat pre-plant occurs in August and September. The fall pre-plant occurs in late October and November. The highest level of ammonia demand is traditionally observed in the spring pre-plant period, from March through May. There are also small fill volumes that move in the off-season to fill the available storage at the dealer level.

Ammonia and UAN are distributed by truck or by railcar. If delivered by truck, products are sold on a freight-on-board basis, and freight is normally arranged by the customer. The nitrogen fertilizer business also owns and leases a fleet of railcars. It also negotiates with distributors that have their own leased railcars to utilize these assets to deliver products. The nitrogen fertilizer business owns all of the truck and rail loading equipment at its facility. It operates two truck loading and eight rail loading racks for each of ammonia and UAN.

The nitrogen fertilizer business markets agricultural products to destinations that produce the best margins for the business. These markets are primarily located on the Union Pacific railroad or destinations which can be supplied by truck. By securing this business directly, the nitrogen fertilizer business reduces its dependence on distributors serving the same customer base, which enables it to capture a larger margin and allows it to better control its product distribution. Most of the agricultural sales are made on a competitive spot basis. The nitrogen fertilizer business also offers products on a

Table of Contents

prepay basis for in-season demand. The heavy in-season demand periods are spring and fall in the corn belt and summer in the wheat belt. The corn belt is the primary corn producing region of the United States, which includes Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Ohio and Wisconsin. The wheat belt is the primary wheat producing region of the United States, which includes Kansas, North Dakota, Oklahoma, South Dakota and Texas. Some of the industrial sales are spot sales, but most are on annual or multiyear contracts. Industrial demand for ammonia provides consistent sales and allows the nitrogen fertilizer business to better manage inventory control and generate consistent cash flow.

Customers

The nitrogen fertilizer business sells ammonia to agricultural and industrial customers. It sells approximately 80% of the ammonia it produces to agricultural customers, in the mid-continent area between North Texas and Canada, and approximately 20% to industrial customers. Agricultural customers include distributors such as MFA, United Suppliers, Inc., Brandt Consolidated Inc., ConAgra Fertilizer, Interchem, and CHS, Inc. Industrial customers include Tessenderlo Kerley, Inc. and National Cooperative Refinery Association. The nitrogen fertilizer business sells UAN products to retailers and distributors. Given the nature of its business, and consistent with industry practice, the nitrogen fertilizer business does not have long-term minimum purchase contracts with any of its customers.

For the years ended December 31, 2005, 2006 and 2007 and the three months ended March 31, 2008, the top five ammonia customers in the aggregate represented 55.2%, 51.9%, 62.1% and 68.4% of the nitrogen fertilizer business ammonia sales, respectively, and the top five UAN customers in the aggregate represented 43.1%, 30.0%, 38.7% and 42.4% of its UAN sales, respectively. During the year ended December 31, 2005, Brandt Consolidated Inc. and MFA accounted for 23.3% and 13.6% of the nitrogen fertilizer business ammonia sales, respectively, and CHS Inc. and ConAgra Fertilizer accounted for 14.7% and 12.7% of its UAN sales, respectively. During the year ended December 31, 2006, Brandt Consolidated Inc. and MFA accounted for 22.2% and 13.1% of the nitrogen fertilizer business ammonia sales, respectively, and ConAgra Fertilizer and CHS Inc. accounted for 8.4% and 6.8% of its UAN sales, respectively. During the year ended December 31, 2007, Brandt Consolidated Inc., MFA and ConAgra Fertilizer accounted for 17.4%, 15.0% and 14.4% of the nitrogen fertilizer business ammonia sales, respectively, and ConAgra Fertilizer accounted for 18.7% of its UAN sales. During the three months ended March 31, 2008, Brandt Consolidated Inc. and National Cooperative Refinery Association accounted for 32.3% and 9.6% of the nitrogen fertilizer business ammonia sales, respectively, and ConAgra Fertilizer accounted for 11.1% of its UAN sales.

Competition

Competition in the nitrogen fertilizer industry is dominated by price considerations. However, during the spring and fall application seasons, farming activities intensify and delivery capacity is a significant competitive factor. The nitrogen fertilizer plant maintains a large fleet of rail cars and seasonally adjusts inventory to enhance its manufacturing and distribution operations.

Domestic competition, mainly from regional cooperatives and integrated multinational fertilizer companies, is intense due to customers sophisticated buying tendencies and production strategies that focus on cost and service. Also, foreign competition exists from producers of fertilizer products manufactured in countries with lower cost natural gas supplies. In certain cases, foreign producers of fertilizer who export to the United States may be subsidized by their respective governments. The nitrogen fertilizer business major competitors include Koch Nitrogen, PCS, Terra and CF Industries, all of which produce more UAN than the nitrogen fertilizer business does.

The nitrogen fertilizer plant s main competition in ammonia marketing are Koch s plants at Beatrice, Nebraska, Dodge City, Kansas and Enid, Oklahoma, as well as Terra s plants in Verdigris and Woodward, Oklahoma and Port Neal, Iowa.

Based on Blue Johnson data regarding total U.S. demand for UAN and ammonia, we estimate that the nitrogen fertilizer plant s UAN production in 2007 represented approximately 4.5% of the total U.S. demand and that the net ammonia produced and marketed at Coffeyville represents less than 1% of the total U.S. demand.

Seasonality

Because the nitrogen fertilizer business primarily sells agricultural commodity products, its business is exposed to seasonal fluctuations in demand for nitrogen fertilizer products in the agricultural industry. As a result, the nitrogen fertilizer business typically generates greater net sales and operating income in the spring. In addition, the demand for fertilizers is affected by the aggregate crop planting decisions and fertilizer application rate decisions of individual farmers who make planting decisions based largely on the prospective profitability of a harvest. The specific varieties and amounts of fertilizer they apply depend on factors like crop prices, farmers current liquidity, soil conditions, weather patterns and the types of crops planted.

Environmental Matters

The petroleum and nitrogen fertilizer businesses are subject to extensive and frequently changing federal, state and local laws and regulations relating to the protection of the environment. These laws, their underlying regulatory requirements and the enforcement thereof impact our petroleum and nitrogen fertilizer businesses by imposing:

- restrictions on operations and/or the need to install enhanced or additional controls;
- the need to obtain and comply with permits, licenses and authorizations;
- liability for the investigation and remediation of contaminated soil and groundwater at current and former facilities and off-site waste disposal locations; and
- specifications for the products manufactured and marketed by our petroleum and nitrogen fertilizer businesses, primarily gasoline, diesel fuel, UAN and ammonia.

The petroleum refining industry is subject to frequent public and governmental scrutiny of its environmental compliance. The laws and regulations to which we are subject are often evolving and many of them have become more stringent or have become subject to more stringent interpretation or enforcement by federal and state agencies. The ultimate impact of complying with existing laws and regulations is not always clearly known or determinable due in part to the fact that our operations may change over time and certain implementing regulations for laws such as the Resource Conservation and Recovery Act (the RCRA), the federal Clean Water Act and the federal Clean Air Act have not yet been finalized, are frequently undergoing governmental or judicial review or are being revised. These regulations and other new hazardous or solid waste, air or water quality standards or stricter fuel regulations could result in increased capital, operating and compliance costs.

The principal environmental risks associated with our petroleum and nitrogen fertilizer businesses are air emissions, releases of hazardous substances into the environment, and the treatment and discharge of wastewater. The legislative and regulatory programs that affect these areas are outlined below. For a discussion of the environmental impact of the 2007 flood and crude oil discharge, see Flood and Crude Oil Discharge Crude Oil Discharge and Flood and Crude Oil Discharge EPA Administrative Order on Consent.

The Federal Clean Air Act

The federal Clean Air Act and its implementing regulations as well as the corresponding state laws and regulations that regulate emissions of pollutants into the air affect our petroleum operations and the nitrogen fertilizer business both directly and indirectly. Direct impacts may occur through federal and state air permitting requirements and/or emission control requirements relating to specific air pollutants. The federal Clean Air Act indirectly affects our petroleum operations and the nitrogen fertilizer business by extensively regulating the air emissions of sulfur dioxide (SO_2), volatile organic compounds, nitrogen oxides and other compounds including those emitted by mobile sources, which are direct or indirect users of our products.

Some or all of the standards promulgated pursuant to the federal Clean Air Act, or any future promulgations of standards, may require the installation of controls or changes to our petroleum operations or the nitrogen fertilizer facilities in order to comply. If new controls or changes to operations are needed, the costs could be significant. These new requirements, other requirements of the federal Clean Air Act, or other presently existing or future environmental regulations could cause us to expend substantial amounts to comply and/or permit our refinery to produce products that meet applicable requirements.

Air Emissions. The regulation of air emissions under the federal Clean Air Act requires us to obtain various construction and operating permits and to incur capital expenditures for the installation of certain air pollution control devices at our refinery. Various regulations specific to, or that directly impact, our industry have been implemented, including regulations that seek to reduce emissions from refineries flare systems, sulfur plants, large heaters and boilers, fugitive emission sources and wastewater treatment systems. Some of the applicable programs are the various general and specific source standards under the National Emission Standard for Hazardous Air Pollutants (NESHAP), New Source Performance Standards and New Source Review. We have incurred, and expect to continue to incur, substantial capital expenditures to maintain compliance with these and other air emission regulations.

In March 2004, we entered into a Consent Decree with the U.S. Environmental Protection Agency (the EPA) and the Kansas Department of Health and Environment (the KDHE) to resolve air compliance concerns raised by the EPA and KDHE related to Farmland s prior operation of our oil refinery. Under the Consent Decree, we agreed to install controls on certain process equipment and make certain operational changes at our refinery. As a result of our agreement to install certain controls and implement certain operational changes, the EPA and KDHE agreed not to seek civil penalties, and provided a release from liability for Farmland s alleged noncompliance with the issues addressed by the Consent Decree. Pursuant to the Consent Decree, in the short term, we have increased the use of catalyst additives to the fluid catalytic cracking unit at the facility to reduce emissions of SO_2. We began adding catalyst to reduce oxides of nitrogen (NOx) in 2008. In the long term, we will install controls to minimize both SO_2 and NOx emissions, which under terms of the Consent Decree require that final controls be in place by January 1, 2011. In addition, pursuant to the Consent Decree, we assumed certain cleanup obligations at the Coffeyville refinery and the Phillipsburg terminal. We agreed to retrofit certain heaters at the refinery with Ultra Low NOx burners. All heater retrofits have been completed and we are currently verifying that the heaters meet the Ultra Low NOx standards required by the Consent Decree. The Ultra Low NOx heater technology is in widespread use throughout the industry. There are other permitting, monitoring, record-keeping and reporting requirements associated with the Consent Decree. The overall cost of complying with the Consent Decree is expected to be approximately $41 million, of which approximately $35 million is expected to be capital expenditures and which does not include the cleanup obligations.

Over the course of the last several years, the EPA has embarked on a National Petroleum Refining Initiative alleging industry-wide noncompliance with four marquee issues: New Source Review, flaring, Leak Detection and Repair, and Benzene Waste Operations NESHAP. The Petroleum Refining Initiative has resulted in many refiners entering into consent decrees imposing civil penalties and requiring substantial expenditures for additional or enhanced pollution control. The EPA has indicated that it will seek all refiners to enter into global settlements pertaining to all marquee issues. Our current Consent Decree covers some, but not all, of the marquee issues. To the extent that we were to agree to enter into a global settlement, we believe our incremental capital exposure would be limited primarily to the retrofit and replacement of certain existing heaters and boilers over a five to seven year timeframe. We also would incur additional operating expenses to enhance our

flaring and leak detection and control programs. In addition, consistent with other refiners that have entered into global settlements, we may be required to pay a civil penalty.

Title V Air Permitting. The petroleum refinery is a major source of air emissions under the Title V permitting program of the federal Clean Air Act. A final Class I (major source) operating permit was issued for our oil refinery in August 2006. We are currently in the process of amending the Title V permit to include the recently approved expansion project permit and the continuous catalytic reformer permit. The nitrogen fertilizer plant has amended its Title V permit application to contain all terms and conditions imposed under its new Prevention of Significant Deterioration (PSD) permit and all other air permits and/or approvals in place. We do not anticipate significant cost or difficulty in obtaining the Title V operating air permit for the nitrogen fertilizer plant. We believe that we hold all material air permits required to operate the Phillipsburg Terminal and our crude oil transportation company s facilities.

Release Reporting

The release of hazardous substances or extremely hazardous substances into the environment is subject to release reporting of threshold quantities under federal and state environmental laws. Our petroleum operations and the nitrogen fertilizer business periodically experience releases of hazardous substances and extremely hazardous substances that could cause our petroleum business and/or the nitrogen fertilizer business to become the subject of a government enforcement action or third-party claims.

The nitrogen fertilizer facility experienced an ammonia release as a result of a malfunction in August 2007 and reported the excess ammonia emissions to the EPA and KDHE. The EPA has investigated the release and has requested additional data. Our incident investigation related to the release indicates that the malfunction could not have been reasonably anticipated or avoided and we have forwarded our results to the EPA.

As a result of an inspection by OSHA following the August 2007 ammonia release OSHA issued citations against both the nitrogen fertilizer facility and the refinery seeking penalties totaling $163,000. We have agreed to settle all allegations as a result of this incident with payment of a $163,000 penalty and review and, if necessary, implement improvements in general health and safety programs at each facility, which may include integrating the plant alarm and notification systems.

Fuel Regulations

Tier II, Low Sulfur Fuels. In February 2000, the EPA promulgated the Tier II Motor Vehicle Emission Standards Final Rule for all passenger vehicles, establishing standards for sulfur content in gasoline. These regulations mandate that the sulfur content of gasoline at any refinery shall not exceed 30 ppm during any calendar year beginning January 1, 2006. Such compliant gasoline is referred to as Ultra Low Sulfur Gasoline (ULSG). Phase-in of these requirements began during 2004. In addition, in January 2001, the EPA promulgated its on-road diesel regulations, which required a 97% reduction in the sulfur content of diesel sold for highway use by June 1, 2006, with full compliance by January 1, 2010. The EPA adopted a rule for off-road diesel in May 2004. The off-road diesel regulations will generally require a 97% reduction in the sulfur content of diesel sold for off-road use by June 1, 2010. Such compliant diesel is referred to as Ultra Low Sulfur Diesel (ULSD). Our production of ULSG and ULSD made us eligible for significant tax benefits in 2007, and we expect to be eligible for significant tax benefits in 2008 as well.

Modifications have been and will continue to be required at our refinery as a result of the Tier II gasoline and low sulfur diesel standards. In February 2004 the EPA granted us approval under a hardship waiver that defers meeting final low sulfur Tier II gasoline standards until January 1, 2011 and deferred meeting low sulfur highway diesel requirements until January 1, 2007. We completed the construction and startup phase of our Ultra Low Sulfur Diesel Hydrodesulfurization unit in late 2006 in accordance with the conditions of the hardship waiver. We are currently continuing our phased

Table of Contents

construction and startup of projects related to meeting our compliance date with ULSG standards and may agree to meet these standards one year early as described below. Compliance with the Tier II gasoline and on-road diesel standards required us to spend approximately $133 million during 2006 and approximately $103 million during 2007, and we estimate that compliance will require us to spend approximately $68 million between 2008 and 2010. Changes in equipment or construction costs could require significantly greater expenditures.

In 2007, as a result of the flood, our refinery exceeded the required average gasoline sulfur standard mandated by the hardship waiver. We are re-negotiating provisions of the hardship waiver and have agreed in principal to meet the final low sulfur Tier II gasoline standards by January 1, 2010 (one year earlier than required under the hardship waiver) in consideration for the EPA s agreement not to seek a penalty for the 2007 sulfur exceedance and higher gasoline sulfur limits for 2008 and 2009.

Greenhouse Gas Emissions

The United States Congress has considered various proposals to reduce greenhouse gas emissions, but none have become law, and presently, there are no federal mandatory greenhouse gas emissions requirements. While it is probable that Congress will adopt some form of federal mandatory greenhouse gas emission reductions legislation in the future, the timing and specific requirements of any such legislation are uncertain at this time. In the absence of existing federal regulations, a number of states have adopted regional greenhouse gas initiatives to reduce CO_2 and other greenhouse gas emissions. In 2007, a group of Midwest states, including Kansas (where our refinery and the nitrogen fertilizer facility are located), formed the Midwestern Greenhouse Gas Accord, which calls for the development of a cap-and-trade system to control greenhouse gas emissions and for the inventory of such emissions. However, the individual states that have signed on to the accord must adopt laws or regulations implementing the trading scheme before it becomes effective, and the timing and specific requirements of any such laws or regulations in Kansas are uncertain at this time.

In 2007, the U.S. Supreme Court decided that CO_2 is an air pollutant under the federal Clean Air Act for the purposes of vehicle emissions. Similar lawsuits have been filed seeking to require the EPA to regulate CO_2 emissions from stationary sources, such as our refinery and the fertilizer plant, under the federal Clean Air Act. Our refinery and the nitrogen fertilizer plant produce significant amounts of CO_2 that are vented into the atmosphere. If the EPA regulates CO_2 emissions from facilities such as ours, we may have to apply for additional permits, install additional controls to reduce CO_2 emissions or take other as yet unknown steps to comply with these potential regulations. For example, we may have to purchase CO_2 emission reduction credits to reduce our current emissions of CO_2 or to offset increases in CO_2 emissions associated with expansions of our operations.

Compliance with any future legislation or regulation of greenhouse gas emissions, if it occurs, may result in increased compliance and operating costs and may have a material adverse effect on our results of operations, financial condition, and the ability of the nitrogen fertilizer business to make distributions. In anticipation of the potential legislation or regulation of greenhouse gas emissions, the nitrogen fertilizer business is looking into initiatives to reduce greenhouse gas emissions, particularly CO_2, and is working with a company involved in CO_2 capture and storage systems to try to develop plans whereby the nitrogen fertilizer business may, in the future, either sell approximately 850,000 tons per year of high purity CO_2 produced by the nitrogen fertilizer plant to oil and gas exploration and production companies to enhance oil recovery or pursue an economic means of geologically sequestering such CO_2. This project is currently in development, but, if completed, is expected to include either the direct sale of CO_2 or the sale of verified emission reduction credits should the credits accrete value in the future due to the implementation of mandatory emissions caps for CO_2.

Table of Contents

The Clean Water Act

The federal Clean Water Act of 1972 affects our petroleum operations and the nitrogen fertilizer business by regulating the treatment of wastewater and imposing restrictions on effluent discharges into, or impacting, navigable water. Regular monitoring, reporting requirements and performance standards are preconditions for the issuance and renewal of permits governing the discharge of pollutants into water. Our petroleum business maintains numerous discharge permits as required under the National Pollutant Discharge Elimination System program of the federal Clean Water Act and has implemented internal programs to oversee our compliance efforts. Our nitrogen fertilizer facility operates under pretreatment requirements and has a permit to discharge our process wastewater to the local publicly owned treatment works.

All of our facilities are subject to Spill Prevention, Control and Countermeasures (SPCC) requirements under the Clean Water Act. In 2004, certain requirements of the rule were extended, and additional modifications are expected. When the modifications to the SPCC rule become final, we may be required to make capital expenditures in order to comply with the modified rule; however, we do not anticipate that any such costs will be significant.

In addition, we are regulated under the Oil Pollution Act of 1990 (the Oil Pollution Act). Among other requirements, the Oil Pollution Act requires the owner or operator of a tank vessel or facility to maintain an emergency oil response plan to respond to releases of oil or hazardous substances. We have developed and implemented such a plan for each of our facilities covered by the Oil Pollution Act. Also, in case of such releases, the Oil Pollution Act requires responsible parties to pay the resulting removal costs and damages, provides for substantial civil penalties, and authorizes the imposition of criminal and civil sanctions for violations. States where we have operations have laws similar to the Oil Pollution Act.

Wastewater Management. We have a wastewater treatment plant at our refinery permitted to handle an average flow of 2.2 million gallons per day. The facility uses a complete mix activated sludge (CMAS) system with three CMAS basins. The plant operates pursuant to a KDHE permit. We are also implementing a comprehensive spill response plan in accordance with the EPA rules and guidance.

Ongoing fuels terminal and asphalt plant operations at Phillipsburg generate only limited wastewater flows (e.g., boiler blowdown, asphalt loading rack condensate, groundwater treatment). These flows are handled in a wastewater treatment plant that includes a primary clarifier, aerated secondary clarifier, and a final clarifier to a lagoon system. The plant operates pursuant to a KDHE Water Pollution Control Permit. To control facility runoff, management implements a comprehensive Spill Response Plan. Phillipsburg also has a timely and current application on file with the KDHE for a separate storm water control permit.

Resource Conservation and Recovery Act (RCRA)

Our operations are subject to the RCRA requirements for the generation, treatment, storage and disposal of hazardous wastes. When feasible, RCRA materials are recycled instead of being disposed of on-site or off-site. RCRA establishes standards for the management of solid and hazardous wastes. Besides governing current waste disposal practices, RCRA also addresses the environmental effects of certain past waste disposal operations, the recycling of wastes and the regulation of underground storage tanks containing regulated substances.

Waste Management. There are two closed hazardous waste units at the refinery and eight other hazardous waste units in the process of being closed pending state agency approval. In addition, one closed interim status hazardous waste landfarm located at the Phillipsburg terminal is under long-term post closure care.

We have set aside approximately $3.2 million in financial assurance for closure/post-closure care for hazardous waste management units at the Phillipsburg terminal and the Coffeyville refinery.

Impacts of Past Manufacturing. We are subject to a 1994 EPA administrative order related to investigation of possible past releases of hazardous materials to the environment at the refinery. In accordance with the order, we have documented existing soil and ground water conditions, which require investigation or remediation projects. The Phillipsburg terminal is subject to a 1996 EPA administrative order related to investigation of possible past releases of hazardous materials to the environment at the Phillipsburg terminal, which operated as a refinery until 1991. The Consent Decree that we signed with the EPA and KDHE requires us to complete all activities in accordance with federal and state rules and to maintain financial assurance (e.g., a bond or letter of credit) for the costs of doing so. See Financial Assurance, below.

The anticipated remediation costs through 2011 were estimated, as of March 31, 2008, to be as follows (in millions):

Facility	Site Investigation Costs	Capital Costs	Total O&M Costs Through 2011	Total Estimated Costs Through 2011
Coffeyville Oil Refinery	$ 0.3	$	$ 1.1	$ 1.4
Phillipsburg Terminal	0.3		1.9	2.2
Total Estimated Costs	$ 0.6	$	$ 3.0	$ 3.6

These estimates are based on current information and could go up or down as additional information becomes available through our ongoing remediation and investigation activities. At this point, we have estimated that, over ten years starting in 2008, we will spend between $5.8 million and $6.3 million to remedy impacts from past manufacturing activity at the refinery and to address existing soil and groundwater contamination at the Phillipsburg terminal. It is possible that additional costs will be required after this ten year period.

Financial Assurance. We were required in the Consent Decree to establish $15.0 million in financial assurance to cover the projected cleanup costs under the 1994 and 1996 EPA administrative orders described above, in the event we failed to fulfill our clean-up obligations. In accordance with the Consent Decree, this financial assurance is partially secured by a bond posted by Original Predecessor, Farmland. We are replacing the financial assurance currently provided by Farmland on a quarterly basis and, so far, have replaced approximately $4.5 million. At this point, it is not clear what the amount of financial assurance will be when replaced. Although it may be significant, we do not expect it will be more than $15.0 million.

Environmental Insurance. We have entered into environmental insurance policies as part of our overall risk management strategy. Our primary pollution legal liability policy provides us with an aggregate limit of $25.0 million subject to a $5.0 million self-insured retention. This policy covers cleanup costs resulting from pre-existing or new pollution conditions and bodily injury and property damage resulting from pollution conditions. It also includes a $25.0 million business interruption sub-limit subject to a 45-day waiting period. Our excess pollution legal liability policies provide us with up to an additional $50.0 million of aggregate limit. The excess pollution legal liability policies may not provide coverage until the $25.0 million of underlying limit available in the primary pollution legal liability policy has been exhausted. We also have a financial assurance policy linked to our pollution legal liability policy that provides a $4.0 million limit per pollution incident and an $8.0 million aggregate policy limit related specifically to closed RCRA units at the refinery and the Phillipsburg terminal. Each of these policies contains substantial exclusions; as such, there can be no assurance that we will have coverage for all or any particular liabilities. For a discussion of our insurance policies that relate to coverage for the 2007 flood and crude oil discharge, see Flood and Crude Oil Discharge Insurance.

Table of Contents

Environmental Remediation

Under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), RCRA, and related state laws, certain persons may be liable for the release or threatened release of hazardous substances. These persons include the current owner or operator of property where a release or threatened release occurred, any persons who owned or operated the property when the release occurred, and any persons who disposed of, or arranged for the transportation or disposal of, hazardous substances at a contaminated property. Liability under CERCLA is strict, retroactive and joint and several, so that any responsible party may be held liable for the entire cost of investigating and remediating the release of hazardous substances. The liability of a party is determined by the cost of investigation and remediation, the portion and toxicity of the hazardous substance(s) the party contributed, the number of solvent potentially responsible parties, and other factors.

As is the case with all companies engaged in similar industries, we face potential exposure from future claims and lawsuits involving environmental matters, including soil and water contamination, personal injury or property damage allegedly caused by hazardous substances that we, or potentially Farmland, manufactured, handled, used, stored, transported, spilled, released or disposed of. We cannot assure you that we will not become involved in future proceedings related to our release of hazardous or extremely hazardous substances or that, if we were held responsible for damages in any existing or future proceedings, such costs would be covered by insurance or would not be material.

Safety, Health and Security Matters

We operate a comprehensive safety, health and security program, involving the active participation of employees at all levels of the organization. We measure our success in the health and safety area primarily through the use of injury frequency rates administered by OSHA. In 2007, our oil refinery experienced a 75% reduction in injury frequency rates and the nitrogen fertilizer plant experienced a 81% reduction in such rate as compared to the average of the previous three years. The recordable injury rate reflects the number of recordable incidents (injuries as defined by OSHA) per 200,000 hours worked, and for the year ended December 31, 2007, we had a recordable injury rate of 0.50 in our petroleum business and 0.93 in the nitrogen fertilizer business, which did not have a single lost-time accident. Our recordable injury rate for all business units was 0.28 for the year ended December 31, 2007, and 0.57 for the quarter ended March 31, 2008. In 2006, our refinery achieved one year worked without a lost-time accident, which based on available records, had never been achieved in the 100 year history of the facility. In March 2007 our petroleum business achieved a milestone after operating for 1,000,000 consecutive man hours without a lost-time accident. For the year ended December 31, 2007, our nitrogen fertilizer business did not have a single lost-time accident. Despite our efforts to achieve excellence in our safety and health performance, we cannot assure you that there will not be accidents resulting in injuries or even fatalities. We have implemented a new incident investigation program that is intended to improve the safety for our employees by identifying the root cause of accidents and potential accidents and by correcting conditions that could cause or contribute to accidents or injuries. We routinely audit our programs and consider improvements in our management systems.

Process Safety Management. We maintain a Process Safety Management (PSM) program. This program is designed to address all facets associated with OSHA guidelines for developing and maintaining a PSM program. We will continue to audit our programs and consider improvements in our management systems and equipment.

We have evaluated and continue to implement improvements at our refinery s process units, process pumping and piping systems and emergency isolation valves for control of process flows. We currently estimate the costs for implementing any recommended improvements to be between $7 million and $9 million over a period of four years. These improvements, if warranted, would reduce

Table of Contents

the risk of releases, spills, discharges, leaks, accidents, fires or other events and minimize the potential effects thereof. We are currently completing the start-up of the final additions of a new $27 million refinery flare system that replaced any remaining atmospheric sumps in our refinery. We have assessed the potential impacts on building occupancy caused by the location and design of our refinery and fertilizer plant control rooms and operator shelters. We have relocated non-essential personnel and contractors away from the process areas and are currently constructing and installing permanent blast-proof operator control rooms and outside shelters. We expect the costs to upgrade or relocate these areas to be between $4 million and $6 million over the next two to five years.

In 2007, OSHA began PSM inspections of all refineries under its jurisdiction as part of its National Emphasis Program (the NEP) following OSHA s investigation of PSM issues relating to the multiple fatality explosion and fire at the BP Texas City facility in 2005. Completed NEP inspections have resulted in OSHA levying significant fines and penalties against most of the refineries inspected to date. At this time, our refinery has not been inspected in connection with OSHA s NEP program. Although we believe that our PSM program is in substantial compliance with OSHA PSM regulations, an OSHA NEP inspection could result in the imposition of significant fines and penalties as well as significant additional capital expenditures related to PSM.

Emergency Planning and Response. We have an emergency response plan that describes the organization, responsibilities and plans for responding to emergencies in the facilities. This plan is communicated to local regulatory and community groups. We have on-site warning siren systems and personal radios. We will continue to audit our programs and consider improvements in our management systems and equipment.

Security. We have a comprehensive security program to protect our refinery and the nitrogen fertilizer facility from unauthorized entry and exit and potential acts of terrorism. Recent changes in the U.S. Department of Homeland Security rules and requirements may require enhancements and improvements to our current program.

Community Advisory Panel. We have developed and continue to support ongoing discussions with the community to share information about our operations and future plans. Our community advisory panel includes wide representation of residents, business owners and local elected representatives for the city and county.

Employees

As of March 31, 2008, 455 employees were employed in our petroleum business, 110 were employed by the nitrogen fertilizer business and 49 employees were employed at our offices in Sugar Land, Texas and Kansas City, Kansas.

We entered into collective bargaining agreements which, as of March 31, 2008, covered approximately 42% of our employees (all of whom work in our petroleum business) with the Metal Trades Union and the United Steelworkers of America. The collective bargaining agreements expire in March 2009. We believe that our relationship with our employees is good.

Prior to the consummation of our initial public offering, we entered into a services agreement with the Partnership and the managing general partner of the Partnership pursuant to which we agreed to provide certain management and other services to the Partnership, the managing general partner of the Partnership, and the nitrogen fertilizer business. The services we provide under the agreement include the following services, among others:

- services by our employees as the Partnership s corporate executive officers, including chief executive officer, chief operating officer, chief financial officer, general counsel, fertilizer general manager, and vice president for environmental, health and safety, except that those who serve in such capacities under the agreement serve the Partnership on a shared, part-time basis only, unless we and the Partnership agree otherwise;

Table of Contents

administrative and professional services, including legal, accounting services, human resources, insurance, tax, credit, finance, government affairs and regulatory affairs;

management of the property of the Partnership and Coffeyville Resources Nitrogen Fertilizers, LLC, a subsidiary of the Partnership, in the ordinary course of business;

recommendations on capital raising activities, including the issuance of debt or equity securities, the entry into credit facilities and other capital market transactions;

managing or overseeing litigation and administrative or regulatory proceedings, and establishing appropriate insurance policies for the Partnership, and providing safety and environmental advice;

recommending the payment of distributions; and

managing or providing advice for other projects as may be agreed by us and the managing general partner of the Partnership from time to time.

Personnel performing the actual day-to-day business and operations of the Partnership at the plant level are employed directly by the Partnership and its subsidiaries, which bear all personnel costs for these employees. We pay all compensation and benefits for our executive officers, including executive officers who perform services for the Partnership, and we are reimbursed by the managing general partner of the Partnership for a pro rata portion of such compensation and benefits based on the percentage of time each officer works for the Partnership. For more information on this services agreement, see The Nitrogen Fertilizer Limited Partnership Intercompany Agreements.

Properties

The following table contains certain information regarding our principal properties

Location	Acres	Own/Lease	Use
Coffeyville, KS	440	Own	Oil refinery, fertilizer plant and office buildings
Phillipsburg, KS	200	Own	Terminal facility
Montgomery County, KS (Coffeyville Station)	20	Own	Crude oil storage
Montgomery County, KS (Broome Station)	20	Own	Crude oil storage
Bartlesville, OK	25	Own	Truck storage and office buildings
Winfield, KS	5	Own	Truck storage
Cushing, OK	185	Own	Crude oil storage
Cowley County, KS (Hooser Station)	80	Own	Crude oil storage
Holdrege, NE	7	Own	Crude oil storage
Stockton, KS	6	Own	Crude oil storage
Sugar Land, TX	22,000 (square feet)	Lease	Office space
Kansas City, KS	18,400 (square feet)	Lease	Office space

Our executive offices are located at 2277 Plaza Drive in Sugar Land, Texas. We lease approximately 22,000 square feet at that location. Rent under the lease is currently approximately $515,000 annually, plus operating expenses, increasing to approximately $550,000 in 2009. The lease expires in 2011. Rent under our lease for the Kansas City office space is approximately $268,000 annually, plus a portion of operating expenses and taxes. The lease expires in 2009. We expect that our current owned and leased facilities will be sufficient for our needs over the next twelve months.

Table of Contents

In January 2008, we transferred ownership of certain parcels of land, including land that the fertilizer plant is situated on, to the Partnership so that the Partnership would be able to operate the fertilizer plant on its own land. Additionally, in October 2007, we entered into a new cross easement agreement with the Partnership so that both we and the Partnership will be able to access and utilize each other s land in certain circumstances in order to operate our respective businesses in a manner to provide flexibility for both parties to develop their respective properties, without depriving either party of the benefits associated with the continuous reasonable use of the other parties property. For more information on this cross-easement agreement, see The Nitrogen Fertilizer Limited Partnership Intercompany Agreements.

As of December 31, 2007, we had storage capacity for 769,000 barrels of gasoline, 1,068,000 barrels of distillates, 928,000 barrels of intermediates and 3,364,000 barrels of crude oil. The crude oil storage consisted of 674,000 barrels of refinery storage capacity, 520,000 barrels of field storage capacity and 2,170,000 barrels of storage at Cushing, Oklahoma.

Legal Proceedings

We are, and will continue to be, subject to litigation from time to time in the ordinary course of our business, including matters such as those described above under Environmental Matters . We are not party to any pending legal proceedings that we believe will have a material impact on our business, and there are no existing legal proceedings where we believe that the reasonably possible loss or range of loss is material.

FLOOD AND CRUDE OIL DISCHARGE

Overview

During the weekend of June 30, 2007, torrential rains in southeastern Kansas caused the Verdigris River to overflow its banks and flood the city of Coffeyville. The river crested more than ten feet above flood stage, setting a new record for the river. Approximately 2,000 citizens and hundreds of homes throughout the city of Coffeyville were affected. Our refinery and the nitrogen fertilizer plant, both of which are located in close proximity to the Verdigris River, were severely flooded and were forced to conduct emergency shutdowns and evacuations. The majority of the refinery s process units were under four to six feet of water and portions of the refinery s tank farms and wastewater treatment area were covered with eight to ten feet of water. As a result, the refinery and nitrogen fertilizer facilities sustained major damage and required extensive repairs.

Property Damage and Lost Earnings

The refinery sustained damage to a large number of pumps, motors, tanks, control rooms and other buildings, electrical equipment and electronic controls, and required significant clean-up in the areas surrounding the water and wastewater treatment plants. We hired nearly 1,000 extra contract workers to help repair and replace damaged equipment. The refinery started operating its reformer on August 6, 2007 and began to charge crude oil to the facility on August 9, 2007. Substantially all of the refinery s units were in operation by August 20, 2007.

The nitrogen fertilizer facility, situated on slightly higher ground, sustained less damage than the refinery. Bringing the nitrogen fertilizer plant back on line involved replacing or repairing 30% of all electric drives, repairing 60% of the plant s motor control centers, refurbishing 100% of the plant s distributive control systems and programmable logic controllers and repairing the main control room. The nitrogen fertilizer facility initiated startup at its production facility on July 13, 2007.

As of March 31, 2008, total third party costs to repair the refinery and fertilizer facilities were approximately $82.5 million and $4.0 million, respectively. In addition, we currently estimate that approximately $2.1 million in third party costs related to the repair of flood damaged property will be recorded in future periods. We are currently uncertain how much of these amounts we will be able to recover through insurance. See Insurance.

Crude Oil Discharge

Because the Verdigris River rose so rapidly during the flood, much faster than predicted, our employees had to shut down and secure the refinery in six to seven hours, rather than the 24 hours typically needed for such an effort. Despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. In particular, crude oil and its fractions were released from refinery storage tanks and the refinery sewer system. Crude oil was carried by floodwaters downstream from our refinery and into residential and commercial areas.

In response to the crude oil discharge, on July 1, 2007 we established an incident command center and assembled a team of environmental consultants and oil spill response contractors to manage our response to the crude oil discharge.

The O BRIEN S Group managed the overall process, including containment and recovery. The O BRIEN S Group is the largest provider of emergency preparedness and crisis management services to the energy and internal shipping industries.

United States Environmental Services, LLC provided operations support. This firm is a full-service environmental contracting company specializing in environmental emergency response, in-plant industrial services, contaminated site remediation, chemical/biological terrorism response, safety training and industrial hygiene.

The Center for Toxicology and Environmental Health oversaw sampling, analysis and reporting for the operation. This firm specializes in toxicology, risk assessment, industrial hygiene, occupational health and response to emergencies involving the release or threat of release of chemicals.

On July 2, 2007, the EPA dispatched additional oil spill response contractors to the site with the EPA s mobile command post to monitor and coordinate pollution assessments related to the flooding and the crude oil discharge.

Beginning on or about July 2, 2007, the EPA s oil spill response contractors and we began jointly conducting daily aerial overflights of the Coffeyville area and our refinery. On or about July 2, 2007, (a) crude oil from the refinery was observed to be in the flood waters surrounding the above-ground storage tanks located at our refinery and (b) oil was observed in the Verdigris River and in flood waters that had inundated a portion of the city of Coffeyville.

Representatives from the KDHE and the Oklahoma Department of Environmental Quality have also been heavily involved in the response to the oil discharge.

EPA Administrative Order on Consent

On July 10, 2007, we entered into an administrative order on consent (the Consent Order) with the EPA. As set forth in the Consent Order, the EPA concluded that the discharge of oil from our refinery caused and may continue to cause an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, we agreed to perform specified remedial actions to respond to the discharge of crude oil from our refinery.

Under the Consent Order, within 90 days after the completion of such remedial action, we will submit to the EPA for review and approval a final report summarizing the actions taken to comply with the Consent Order. We have worked with the EPA throughout the recovery process and we could be required to reimburse the EPA s costs under the federal Oil Pollution Act. Except as otherwise set forth in the Consent Order, the Consent Order does not limit the EPA s rights to seek other legal, equitable or administrative relief or action as it deems appropriate and necessary against us or from requiring us to perform additional activities pursuant to applicable law. Among other things, the EPA reserved the right to assess administrative penalties against us and/or to seek civil penalties against us. In addition, the Consent Order states that it is not a satisfaction of or discharge from any claim or cause of action against us or any person for any liability we or such person may have under statutes or the common law, including any claims of the United States, for penalties, costs and damages.

We expect to substantially complete remediation of the contamination caused by the crude oil discharge by July 31, 2008 and anticipate minor remedial actions thereafter. Total net costs recorded as of March 31, 2008 associated with remediation efforts and third party property damage incurred by the crude oil discharge are approximately $27.3 million. This amount is net of anticipated insurance recoveries of $21.4 million. In 2007, the Company received insurance proceeds of $10.0 million under its property insurance policy, $10.0 million under its environmental policies related to recovery of certain costs associated with the crude oil discharge and $1.5 million under its builders risk policy. These amounts do not include potential fines or penalties which may be imposed by regulatory authorities or costs arising from potential natural resource damages claims (for which we are unable to estimate a range of possible costs at this time) or possible additional damages arising from lawsuits related to the flood.

Property Repurchase Program and Claims for Property Damage

On July 19, 2007 we commenced a program to purchase approximately 330 homes and certain other properties in connection with the flood and the crude oil discharge. We offered to purchase the property of approximately 330 residential landowners (with the consent and cooperation of the city of Coffeyville) for 110% of their pre-flood appraised value (to be established by appraisal conducted without consideration of the flood), without release or other waiver of any rights by the landowners, and without deduction for the greater harm unquestionably caused to these properties by the flood itself. As of March 31, 2008, 322 of these approximately 330 residential properties are under contract. We estimate that this program will cost approximately $17.5 million, excluding certain costs associated with remediation.

In addition, in early July 2007 we opened a claims center in Coffeyville and established a toll-free number to facilitate the recording and processing of claims for compensation by those who may have incurred property and other damages related to the oil discharge. Staff assisted local residents in filing claims related to the 2007 flood and crude oil discharge. We also offered a toll-free number at the claims call center which was answered 24 hours a day. Call center operators collected property owners information and forwarded it to claims adjustors. The claims adjustors contacted property owners to schedule appointments. Operators also directed callers to local, state and federal disaster response agencies for additional assistance. As of the date of this prospectus, we have adjusted most of these claims.

Litigation

As a result of the crude oil discharge, two putative class action lawsuits (one federal and one state) were filed against us and/or our subsidiaries in July 2007. The federal suit, Danny Dunham vs. Coffeyville Resources, LLC, et al., was filed in the United States District Court for the District of Kansas at Wichita (case number 6:07-cv-01186-JTM-DWB). The state suit, Western Plains Alliance, LLC and Western Plains Operations, LLC v. Coffeyville Resources Refining & Marketing, LLC, was filed in the District Court of Montgomery County, Kansas (case number 07CV99I).

Plaintiff s complaint in the federal suit alleged that the crude oil discharge resulted from our negligent operation of the refinery and that class members suffered unspecified damages, including damages to their personal and real property, diminished property value, lost full use and enjoyment of their property, lost or diminished business income and comprehensive remediation costs. The federal suit sought recovery under the federal Oil Pollution Act, Kansas statutory law imposing a duty of compensation on a party that releases any material detrimental to the soil or waters of Kansas, and the Kansas common law of negligence, trespass and nuisance. This suit was dismissed on November 6, 2007 for lack of subject matter jurisdiction, and no appeal was taken.

The state suit sought class certification under applicable law. The proposed class would have consisted of all persons and entities who own or have owned real property within the contaminated area , and all businesses and/or other entities located within the contaminated area . The Court conducted an evidentiary hearing on the issue of class certification on October 24 and 25, 2007 and ruled against class certification, leaving only the original two plaintiffs who have agreed, subject to final documentation, to settle their claims and dismiss the state lawsuit.

We recently received 16 notices of claims under the Oil Pollution Act from private claimants in an aggregate amount of approximately $4.4 million. No lawsuits related to these claims have yet been filed.

Insurance

During and after the time of the 2007 flood and crude oil discharge, Coffeyville Resources, LLC was insured under insurance policies that were issued by a variety of insurers and which covered various risks, such as damage to our property, interruption of our business, environmental cleanup costs, and potential liability to third parties for bodily injury or property damage. These coverages include the following:

Our primary property damage and business interruption insurance program provided $300 million of coverage for flood-related damage, subject to a deductible of $2.5 million per occurrence and a 45-day waiting period for business interruption loss. While we believe that property insurance should cover substantially all of the estimated total physical damage to our property, our insurance carriers have cited potential coverage limitations and defenses that might preclude such a result.

Our builders risk policy provided coverage for property damage to buildings in the course of construction. Flood-related loss or damage was subject to a $100,000 deductible and sub-limit of $50 million.

Our environmental insurance coverage program provided coverage for bodily injury, property damage, and cleanup costs resulting from new pollution conditions. At the time of the flood, the program included a primary policy with a $25.0 million aggregate limit of liability. This policy was subject to a $1 million self-insured retention. In addition, at the time of the flood we had a $25.0 million excess policy that was triggered by exhaustion of the primary policy. The excess policy covered bodily injury and property damage resulting from new pollution conditions, but did not cover cleanup costs.

Our umbrella and excess liability coverage program provided $100 million of coverage for claims in excess of $5.0 million and other applicable insurance for third-party claims of property damage and bodily injury arising out of the sudden and accidental discharge of pollutants.

Coffeyville Resources, LLC promptly notified its insurers of the flood, the crude oil discharge, and related claims and lawsuits. We are in the process of submitting our claims to, responding to information requests from, and negotiating with the insurers with respect to costs and damages related to the 2007 flood and crude oil discharge. Our property insurers have raised a question as to whether our facilities are principally located in Zone A which is subject to a $10 million insurance limit for flood or Zone B which is subject to a $300 million insurance limit for flood. We have reached agreement with 32.5% of our property insurers that our facilities are principally located in Zone B. Our remaining property insurers have not, at this time, agreed to this position. In addition, our primary environmental liability insurance carrier has asserted that our pollution liability claims are for cleanup which is subject to a $10 million sub-limit, rather than property damage which is covered to the limits of the policy. The excess carrier has reserved its rights under the primary carrier s position. While we will vigorously contest the primary carrier s position, we believe that if that position were upheld, our umbrella and excess Comprehensive General Liability policies would continue to provide coverage for these claims. Although each insurer has reserved its rights under various policy exclusions and limitations and has cited potential coverage defenses, we are vigorously pursuing our insurance recovery claims. We expect that ultimate recovery will be subject to negotiation and, if negotiation is unsuccessful, litigation.

Our insurance policies also provide coverage for interruption to the business, including lost profits, and reimbursement for other expenses and costs we have incurred relating to the damages and losses suffered. This coverage, however, applies only to losses incurred after a business interruption of 45 days. Because both the refinery and the nitrogen fertilizer plant were restored to operation within this 45-day period, a majority of the lost profits incurred because of the flood are unlikely to be paid by our business interruption insurance.

Financial Impact on Our Results

Total gross costs recorded due to the flood and related crude oil discharge that were included in our statement of operations for the year ended December 31, 2007 were approximately $146.8 million.

Table of Contents

Of these gross costs, approximately $101.9 million were associated with repair and other matters as a result of the flood damage to our facilities. Included in this cost was $7.6 million of depreciation for temporarily idled facilities, $6.1 million of salaries, $2.2 million of professional fees and $86.0 million for other repair and related costs. There were approximately $44.9 million of costs recorded for the year ended December 31, 2007 related to the third party and property damage remediation as a result of the crude oil discharge.

Total gross costs recorded due to the flood and related oil discharge that were included in our statement of operations for the three months ended March 31, 2008 were approximately $7.6 million. Of these gross costs for the three month period ended March 31, 2008, approximately $3.8 million were associated with repair and other matters as a result of the flood damage to our facilities. Included in this cost was $0.3 million of professional fees and $3.5 million for other repair and related costs. There were also $3.8 million of costs recorded related to the third party and property damage remediation as a result of the crude oil discharge. We anticipate that approximately $2.1 million in additional third party costs related to the repair of flood damaged property will be recorded in future periods.

As of March 31, 2008, we had received insurance proceeds of $10.0 million under our property insurance policy, an additional $10.0 million under our environmental policies related to recovery of certain costs associated with the crude oil discharge and $1.5 million under our Builder s Risk Insurance Policy. Although we believe that we will recover substantial additional sums under our insurance policies, we are not sure of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of our claims. The difference between what we ultimately receive under our insurance policies compared to what has been recorded in our financial statements could be material to our financial statements. Ultimate recovery may require litigation. We could recover substantially less than our full claim.

Below is a summary of the gross cost and reconciliation of the insurance receivable as of March 31, 2008 (in millions):

	Total Costs	
Total gross costs incurred	$	154.5
Total insurance receivable		(107.2)
Net costs associated with the flood	$	47.3

	Receivable Reconciliation	
Total insurance receivable	$	107.2
Less insurance proceeds received		(21.5)
Insurance receivable	$	85.7

MANAGEMENT

Executive Officers and Directors

The following table sets forth the names, positions and ages of the executive officers and directors of CVR Energy. We also indicate in the biographies below which executive officers and directors of CVR Energy also hold similar positions with the managing general partner of the Partnership. Senior management of CVR Energy manages the Partnership pursuant to the services agreement described under The Nitrogen Fertilizer Limited Partnership Intercompany Agreements. All of the named executive officers of CVR Energy listed below will devote all of their time to CVR Energy and its wholly-owned subsidiaries, except that certain of them will also devote a portion of their time to the management of the Partnership.

Name	Age	Position
John J. Lipinski	57	Chairman of the Board of Directors, Chief Executive Officer and President
Stanley A. Riemann	57	Chief Operating Officer
James T. Rens	41	Chief Financial Officer and Treasurer
Edmund S. Gross	57	Senior Vice President, General Counsel and Secretary
Daniel J. Daly, Jr.	62	Executive Vice President, Strategy
Robert W. Haugen	50	Executive Vice President, Refining Operations
Wyatt E. Jernigan	56	Executive Vice President, Crude Oil Acquisition and Petroleum Marketing
Kevan A. Vick	54	Executive Vice President and Fertilizer General Manager
Christopher G. Swanberg	50	Vice President, Environmental, Health and Safety
Scott L. Lebovitz	32	Director
Regis B. Lippert	68	Director
George E. Matelich	52	Director
Steve A. Nordaker	61	Director
Stanley de J. Osborne	37	Director
Kenneth A. Pontarelli	37	Director
Mark E. Tomkins	52	Director

John J. Lipinski has served as our chairman of the board since October 2007, our chief executive officer and president and a member of our board since September 2006, chief executive officer and president of Coffeyville Acquisition LLC since June 2005 and chief executive officer and president of Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC since October 2007. Since October 2007, Mr. Lipinski has also served as the chief executive officer, president and a director of the managing general partner of the Partnership. Mr. Lipinski has over 35 years of experience in the petroleum refining and nitrogen fertilizer industries. He began his career with Texaco Inc. In 1985, Mr. Lipinski joined The Coastal Corporation, eventually serving as Vice President of Refining with overall responsibility for Coastal Corporation s refining and petrochemical operations. Upon the merger of Coastal with El Paso Corporation in 2001, Mr. Lipinski was promoted to Executive Vice President of Refining and Chemicals, where he was responsible for all refining, petrochemical, nitrogen-based chemical processing, and lubricant operations, as well as the corporate engineering and construction group. Mr. Lipinski left El Paso in 2002 and became an independent management consultant. In 2004, he became a Managing Director and Partner of Prudentia Energy, an advisory and management firm. Mr. Lipinski graduated from Stevens Institute of Technology with a Bachelor of Engineering (Chemical) and received a Juris Doctor degree from Rutgers University School of Law.

Stanley A. Riemann has served as chief operating officer of our company since September 2006, chief operating officer of Coffeyville Acquisition since June 2005, chief operating officer of

Coffeyville Resources since February 2004 and chief operating officer of Coffeyville Acquisition II and Coffeyville Acquisition III since October 2007. Since October 2007 Mr. Riemann has also served as the chief operating officer of the managing general partner of the Partnership. Prior to joining our company in February 2004, Mr. Riemann held various positions associated with the Crop Production and Petroleum Energy Division of Farmland for over 29 years, including, most recently, Executive Vice President of Farmland and President of Farmland s Energy and Crop Nutrient Division. In this capacity, he was directly responsible for managing the petroleum refining operation and all domestic fertilizer operations, which included the Trinidad and Tobago nitrogen fertilizer operations. His leadership also extended to managing Farmland s interests in SF Phosphates in Rock Springs, Wyoming and Farmland Hydro, L.P., a phosphate production operation in Florida, and managing all company-wide transportation assets and services. Mr. Riemann served as a board member and board chairman on several industry organizations including the Phosphate Potash Institute, the Florida Phosphate Council, and the International Fertilizer Association. He currently serves on the board of The Fertilizer Institute. Mr. Riemann received a B.S. from the University of Nebraska and an M.B.A. from Rockhurst University.

James T. Rens has served as chief financial officer and treasurer of our company since September 2006, chief financial officer and treasurer of Coffeyville Acquisition since June 2005, chief financial officer and treasurer of Coffeyville Resources since February 2004 and chief financial officer and treasurer of Coffeyville Acquisition II and Coffeyville Acquisition III since October 2007. Since October 2007, Mr. Rens has also served as chief financial officer and treasurer of the managing general partner of the Partnership. Before joining our company, Mr. Rens was a consultant to the Original Predecessor s majority shareholder from November 2003 to March 2004, assistant controller at Koch Nitrogen Company from June 2003, which was when Koch acquired the majority of Farmland s nitrogen fertilizer business, to November 2003 and Director of Finance of Farmland s Crop Production and Petroleum Divisions from January 2002 to June 2003. From May 1999 to January 2002, Mr. Rens was controller and chief financial officer of Farmland Hydro L.P. Mr. Rens has spent over 19 years in various accounting and financial positions associated with the fertilizer and energy industry. Mr. Rens received a B.S. degree in accounting from Central Missouri State University.

Edmund S. Gross has served as senior vice president, general counsel and secretary of our company since October 2007, senior vice president, general counsel and secretary of Coffeyville Acquisition II and Coffeyville Acquisition III since October 2007, vice president, general counsel and secretary of our company since September 2006, secretary of Coffeyville Acquisition since June 2005, and general counsel and secretary of Coffeyville Resources since July 2004. Since October 2007 Mr. Gross has also served as the senior vice president, general counsel, and secretary of the managing general partner of the Partnership. Prior to joining Coffeyville Resources, Mr. Gross was Of Counsel at Stinson Morrison Hecker LLP in Kansas City, Missouri from 2002 to 2004, was Senior Corporate Counsel with Farmland Industries, Inc. from 1987 to 2002 and was an associate and later a partner at Weeks, Thomas & Lysaught, a law firm in Kansas City, Kansas, from 1980 to 1987. Mr. Gross received a B.A. in history from Tulane University, a J.D. from the University of Kansas and an M.B.A. from the University of Kansas.

Daniel J. Daly, Jr. has been our executive vice president, strategy since December 2007 and was our Senior Vice President, Administration and Controls from September 2006 through December 2007 and our Vice President, Accounting and Administration from June 2005 through August 2006. From December 2004 to June 2005 Mr. Daly was self-employed as a consultant in mergers & acquisitions. From 1978 to 2001 Mr. Daly worked at Coastal Corporation, first as Manager of Transportation and Supply Operations and then as Controller, Refining Division and Vice President and Controller, Refining and Marketing. Following the merger of Coastal with El Paso in 2001, Mr. Daly served as Vice President and Controller of Tosco Corporation from January 2001 to December 2001. Mr. Daly received a B.S. in commerce from St. Louis University.

Robert W. Haugen joined our business on June 24, 2005 and has served as executive vice president, refining operations at our company since September 2006 and as executive vice

president engineering & construction at Coffeyville Resources since June 24, 2005. Since October 2007 Mr. Haugen has also served as executive vice president, refining operations at Coffeyville Acquisition and Coffeyville Acquisition II. Mr. Haugen brings 25 years of experience in the refining, petrochemical and nitrogen fertilizer business to our company. Prior to joining us, Mr. Haugen was a Managing Director and Partner of Prudentia Energy, an advisory and management firm focused on midstream/downstream energy sectors, from January 2004 to June 2005. On leave from Prudentia, he served as the Senior Oil Consultant to the Iraqi Reconstruction Management Office for the U.S. Department of State. Prior to joining Prudentia Energy, Mr. Haugen served in numerous engineering, operations, marketing and management positions at the Howell Corporation and at the Coastal Corporation. Upon the merger of Coastal and El Paso in 2001, Mr. Haugen was named Vice President and General Manager for the Coastal Corpus Christi Refinery, and later held the positions of Vice President of Chemicals and Vice President of Engineering and Construction. Mr. Haugen received a B.S. in chemical engineering from the University of Texas.

Wyatt E. Jernigan has served as executive vice president, crude oil acquisition and petroleum marketing at our company since September 2006 and as executive vice president crude & feedstocks at Coffeyville Resources since June 24, 2005. Since October 2007 Mr. Jernigan has also served as executive vice president, crude oil acquisition and petroleum marketing at Coffeyville Acquisition and Coffeyville Acquisition II. Mr. Jernigan has 30 years of experience in the areas of crude oil and petroleum products related to trading, marketing, logistics and business development. Most recently, Mr. Jernigan was Managing Director with Prudentia Energy, an advisory and management firm focused on mid-stream/downstream energy sectors, from January 2004 to June 2005. Most of his career was spent with Coastal Corporation and El Paso, where he held several positions in crude oil supply, petroleum marketing and asset development, both domestic and international. Following the merger between Coastal Corporation and El Paso in 2001, Mr. Jernigan assumed the role of Managing Director for Petroleum Markets Originations. Mr. Jernigan attended Virginia Wesleyan College, majoring in sociology, and has training in petroleum fundamentals from the University of Texas.

Kevan A. Vick has served as executive vice president and fertilizer general manager at our company since September 2006, senior vice president at Coffeyville Resources Nitrogen Fertilizers since February 27, 2004 and executive vice president and fertilizer general manager of Coffeyville Acquisition III since October 2007. Since October 2007 Mr. Vick has also served as executive vice president and fertilizer general manager of the managing general partner of the Partnership. He has served on the board of directors of Farmland MissChem Limited in Trinidad and SF Phosphates. He has nearly 30 years of experience in the Farmland organization and is an experienced executive in the nitrogen fertilizer industry, known for both his technical expertise and his in-depth knowledge of the commercial marketplace. Prior to joining Coffeyville Resources, he was general manager of nitrogen manufacturing at Farmland from January 2001 to February 2004. Mr. Vick received a B.S. in chemical engineering from the University of Kansas and is a licensed professional engineer in Kansas, Oklahoma and Iowa.

Christopher G. Swanberg has served as vice president, environmental, health and safety at our company since September 2006, as vice president, environmental, health and safety at Coffeyville Resources since June 2005 and as vice president, environmental, health and safety at Coffeyville Acquisition II and Coffeyville Acquisition III since October 2007. Since October 2007 Mr. Swanberg has also served as vice president, environmental, health and safety at the managing general partner of the Partnership. He has served in numerous management positions in the petroleum refining industry such as Manager, Environmental Affairs for the refining and marketing division of Atlantic Richfield Company (ARCO), and Manager, Regulatory and Legislative Affairs for Lyondell-Citgo Refining. Mr. Swanberg s experience includes technical and management assignments in project, facility and corporate staff positions in all environmental, safety and health areas. Prior to joining Coffeyville Resources, he was vice president of Sage Environmental Consulting, an environmental consulting firm focused on petroleum refining and petrochemicals, from September 2002 to June 2005

and Senior HSE Advisor of Pilko & Associates, LP from September 2000 to September 2002. Mr. Swanberg received a B.S. in environmental engineering technology from Western Kentucky University and an M.B.A. from the University of Tulsa.

Scott L. Lebovitz has been a member of our board since September 2006 and a member of the board of directors of Coffeyville Acquisition II and Coffeyville Acquisition III since October 2007. He was also a member of the board of directors of Coffeyville Acquisition from June 2005 until October 2007. He has also been a member of the board of directors of the managing general partner of the Partnership since October 2007. Mr. Lebovitz is a managing director in the Merchant Banking Division of Goldman, Sachs & Co. Mr. Lebovitz joined Goldman, Sachs & Co. in 1997 and became a managing director in 2007. He is a director of Energy Future Holdings Corp. and Village Voice Media Holdings, LLC. He received his B.S. in commerce from the University of Virginia.

Regis B. Lippert has been a member of our board since June 2007. He was also a member of the board of directors of Coffeyville Acquisition from June 2007 until October 2007. He is the founder, principal shareholder and a director of INTERCAT, Inc., a specialty chemicals company which primarily develops, manufactures, markets and sells specialty catalysts used in petroleum refining. Mr. Lippert serves as president and chief executive officer of INTERCAT, Inc. and its affiliate companies and is a Managing Director of INTERCAT Europe B.V. Mr. Lippert is also a director of Indo Cat Private Limited, an Indian company which is part of a joint venture between INTERCAT, Inc. and Indian Oil Corporation Limited. Prior to founding INTERCAT, Mr. Lippert served from 1981 to 1985 as President, Chief Executive Officer and a director of Katalistiks, Inc., a manufacturer of fluid cracking catalysts which ultimately became a subsidiary of Union Carbide Corporation. From 1979 to 1981, Mr. Lippert was an Executive Vice President with Catalysts Recovery, Inc. In this capacity he was responsible for developing the joint venture which ultimately formed Katalistiks. From 1963 to 1979, Mr. Lippert was employed by Engelhard Minerals and Chemical Co., where he attained the position of Director of Sales and Marketing/Catalysts. Mr. Lippert attended Carnegie-Mellon University where he studied metallurgy. He is a member of the National Petroleum Refiners Association.

George E. Matelich has been a member of our board since September 2006, a member of the board of directors of Coffeyville Acquisition since June 2005 and a member of the board of directors of Coffeyville Acquisition III since October 2007. He has also been a member of the board of directors of the managing general partner of the Partnership since October 2007. Mr. Matelich has been a managing director of Kelso & Company since 1989. Mr. Matelich has been affiliated with Kelso since 1985. Mr. Matelich is a certified public accountant and holds a Certificate in Management Consulting. Mr. Matelich received a B.A. in business administration from the University of Puget Sound and an M.B.A. from the Stanford Graduate School of Business. He is a director of Global Geophysical Services, Inc., Shelter Bay Energy Inc. and Waste Services, Inc. He is also a Trustee of the University of Puget Sound and serves on the National Council of the American Prairie Foundation.

Steve A. Nordaker has been a member of our board since June 2008. He has served as senior vice president, finance of Energy Capital Group Holdings LLC, a development company dedicated to building, owning and operating gasification and IGCC units for the refining, petrochemical and fertilizer industries, since June 2004. Mr. Nordaker has also worked as a financial consultant for various companies in the areas of acquisitions, divestitures, restructuring and financial matters since January 2002. From 1996 through 2001, he was a managing director at J.P. Morgan Securities/JPMorgan Chase Bank in the global chemicals group and global oil & gas group. From 1992 to 1995, he was a managing director in the Chemical Bank worldwide energy, refining and petrochemical group. From 1982 to 1992, Mr. Nordaker served in numerous banking positions in the energy group at Texas Commerce Bank.
Mr. Nordaker was Manager of Projects for the Frantz Company, an engineering consulting firm, from 1977 through 1982 and worked as a Chemical Engineer for UOP, Inc. from 1968 through 1977. Mr. Nordaker received a B.S. in chemical engineering from South Dakota School of Mines and Technology and an M.B.A. from the University of Houston.

Stanley de J. Osborne has been a member of our board since September 2006, a member of the board of directors of Coffeyville Acquisition since June 2005 and a member of the board of directors of Coffeyville Acquisition III since October 2007. He has also been a member of the board of directors of the managing general partner of the Partnership since October 2007. Mr. Osborne was a Vice President of Kelso & Company from 2004 through 2007 and has been a managing director since 2007. Mr. Osborne has been affiliated with Kelso since 1998. Prior to joining Kelso, Mr. Osborne was an Associate at Summit Partners. Previously, Mr. Osborne was an Associate in the Private Equity Group and an Analyst in the Financial Institutions Group at J.P. Morgan & Co. He received a B.A. in Government from Dartmouth College. Mr. Osborne is a director of Custom Building Products, Inc., Global Geophysical Services, Inc., Karat Acquisition LLC, Shelter Bay Energy Inc. and Traxys S.A.

Kenneth A. Pontarelli has been a member of our board since September 2006 and a member of the board of directors of Coffeyville Acquisition II and Coffeyville Acquisition III since October 2007. He has also been a director of the managing general partner of the Partnership since October 2007. He also was a member of the board of directors of Coffeyville Acquisition from June 2005 until October 2007. Mr. Pontarelli is a partner managing director in the Merchant Banking Division of Goldman, Sachs & Co. Mr. Pontarelli joined Goldman, Sachs & Co. in 1992 and became a managing director in 2004. He is a director of CCS, Inc., Cobalt International Energy, L.P., Energy Future Holdings Corp., Knight Holdco LLC, and Kinder Morgan, Inc. He received a B.A. from Syracuse University and an M.B.A. from Harvard Business School.

Mark E. Tomkins has been a member of our board since January 2007. He also was a member of the board of directors of Coffeyville Acquisition from January 2007 until October 2007. Mr. Tomkins has served as the senior financial officer at several large companies during the past ten years. He was Senior Vice President and Chief Financial Officer of Innovene, a petroleum refining and chemical polymers business and a subsidiary of British Petroleum, from May 2005 to January 2006, when Innovene was sold to a strategic buyer. From January 2001 to May 2005 he was Senior Vice President and Chief Financial Officer of Vulcan Materials Company, a publicly traded construction materials and chemicals company. From August 1998 to January 2001 Mr. Tomkins was Senior Vice President and Chief Financial Officer of Chemtura (formerly GreatLakes Chemical Corporation), a publicly traded specialty chemicals company. From July 1996 to August 1998 he worked at Honeywell Corporation as Vice President of Finance and Business Development for its polymers division and as Vice President of Finance and Business Development for its electronic materials division. From November 1990 to July 1996 Mr. Tomkins worked at Monsanto Company in various financial and accounting positions, including Chief Financial Officer of the growth enterprises division from January 1995 to July 1996. Prior to joining Monsanto he worked at Cobra Corporation and as an auditor in private practice. Mr. Tomkins received a B.S. degree in business, with majors in Finance and Management, from Eastern Illinois University and an M.B.A from Eastern Illinois University and is a certified public accountant. Mr. Tomkins is a director of W.R. Grace & Co. and Elevance Renewable Sciences, Inc.

Board of Directors

Our board of directors consists of eight members. The current directors are included above. Our directors are elected annually to serve until the next annual meeting of stockholders or until their successors are duly elected and qualified.

Our board has an audit committee, a compensation committee, a nominating and corporate governance committee and a conflicts committee. Our board of directors has determined that we are a controlled company under the rules of the New York Stock Exchange, and, as a result, qualify for, and may rely on, exemptions from certain corporate governance requirements of the New York Stock Exchange. Pursuant to the controlled company exception to the board of directors and committee composition requirements, we are exempt from the rules that require that (a) our board of directors be comprised of a majority of independent directors, (b) our compensation committee be comprised

solely of independent directors and (c) our nominating and corporate governance committee be comprised solely of independent directors as defined under the rules of the New York Stock Exchange. The controlled company exemption does not modify the independence requirements for the audit committee. The Sarbanes-Oxley Act and the New York Stock Exchange rules require that our audit committee be composed entirely of independent directors, except that our audit committee is only required to have a majority of independent directors until October 22, 2008. The audit committee currently has three members, two of which are independent directors. Thus, the composition of our audit committee satisfies the independence requirements of the New York Stock Exchange and the Sarbanes-Oxley Act. Steve A. Nordaker and Mark E. Tomkins are the independent directors currently serving on the audit committee. Our board has affirmatively determined that Messrs. Steve A. Nordaker and Mark E. Tomkins are independent directors under the rules of the SEC and the NYSE. We do not believe that our reliance on the exemption that allows our audit committee to consist only of a majority of independent directors until October 22, 2008 will adversely affect the ability of our audit committee to act independently and to satisfy applicable independence requirements.

Audit Committee. The members of the audit committee are Messrs. Mark Tomkins, Steve A. Nordaker, and Stanley de J. Osborne. Mr. Tomkins is chairman of the audit committee. Our board of directors has determined that Mr. Tomkins qualifies as an audit committee financial expert. Our board of directors has also determined that Mr. Nordaker and Mr. Tompkins are independent directors as discussed above. The audit committee s responsibilities are to review the accounting and auditing principles and procedures of our company with a view to providing for the safeguard of our assets and the reliability of our financial records by assisting the board of directors in monitoring our financial reporting process, accounting functions and internal controls; to oversee the qualifications, independence, appointment, retention, compensation and performance of our independent registered public accounting firm; to recommend to the board of directors the engagement of our independent accountants; to review with the independent accountants the plans and results of the auditing engagement; and to oversee whistle-blowing procedures and certain other compliance matters.

Compensation Committee. The members of the compensation committee are Messrs. George E. Matelich, Steve A. Nordaker, Kenneth Pontarelli and Mark Tomkins. Mr. George E. Matelich is the chairman of the compensation committee. The principal responsibilities of the compensation committee are to establish policies and periodically determine matters involving executive compensation, recommend changes in employee benefit programs, grant or recommend the grant of stock options and stock awards and provide counsel regarding key personnel selection. A subcommittee of the compensation committee consisting of Messrs. Nordaker and Tomkins will make stock and option awards to the extent deemed necessary or advisable for regulatory purposes. See Compensation Discussion and Analysis.

Nominating and Corporate Governance Committee. The members of the nominating and corporate governance committee are Messrs. Scott L. Lebovitz, Stanley de J. Osborne, John J. Lipinski and Regis B. Lippert. Mr. Scott L. Lebovitz is the chairman of the nominating and corporate governance committee. The principal duties of the nominating and corporate governance committee are to recommend to the board of directors proposed nominees for election to the board of directors by the stockholders at annual meetings and to develop and make recommendations to the board of directors regarding corporate governance matters and practices.

Conflicts Committee. The members of the conflicts committee are Messrs. Steve A. Nordaker and Mark Tomkins. The principal duties of the conflicts committee are to determine, in accordance with the conflicts of interests policy adopted by our board of directors, if the resolution of a conflict of interest between CVR Energy and our subsidiaries, on the one hand, and the Partnership, the Partnership s managing general partner or any subsidiary of the Partnership, on the other hand, is fair and reasonable to us.

Table of Contents

Compensation Committee Interlocks and Insider Participation

Our compensation committee is comprised of Messrs. George E. Matelich, Steve A. Nordaker, Kenneth A. Pontarelli and Mark E. Tomkins. Mr. Matelich is a managing director of Kelso & Company and Mr. Pontarelli is a partner managing director in the Merchant Banking Division of Goldman, Sachs & Co. For a description of the Company s transactions with certain affiliates of Kelso & Company and certain affiliates of Goldman, Sachs & Co., see Certain Relationships and Related Party Transactions Transactions with the Goldman Sachs Funds and the Kelso Funds below.

Mr. John J. Lipinski, our chairman of the board and chief executive officer, is also a director of and serves on the compensation committee of INTERCAT, Inc., a privately held company of which Regis B. Lippert, who serves as a director on our board, is the chief executive officer. Otherwise, no interlocking relationship exists between our board or compensation committee and the board of directors or compensation committee of any other company.

Table of Contents

COMPENSATION DISCUSSION AND ANALYSIS

Executive Compensation

Overview

The compensation committee of the board of directors oversees companywide compensation practices and has specifically reviewed, developed and administered executive compensation programs and made recommendations to the board of directors of Coffeyville Acquisition LLC (prior to our initial public offering) and CVR Energy (following our initial public offering) on compensation matters. Messrs. George E. Matelich, Kenneth Pontarelli and John J. Lipinski served as members of Coffeyville Acquisition LLC s committee during 2006 and prior to our initial public offering. Following our initial public offering, our board of directors established a compensation committee for CVR Energy comprised of Messrs. George E. Matelich (as chairperson), Kenneth Pontarelli, Wesley Clark and Mark Tomkins, which took over the duties of the compensation committee of the board of directors of Coffeyville Acquisition LLC. As of June 2008, Messrs. George E. Matelich (as chairperson), Steve A. Nordaker, Kenneth Pontarelli and Mark Tomkins are the members of our compensation committee. For purposes of this Compensation Discussion and Analysis, the board of directors and the compensation committee refer to the board of directors and compensation committee of Coffeyville Acquisition LLC prior to our initial public offering and CVR Energy following our initial public offering. The definitions of certain defined terms used in this Compensation Discussion and Analysis, including Phantom Unit Plan I, Phantom Unit Plan II, phantom points, phantom service points, phantom performance points, common units, profits interests, override units, operating units and value units, among others, are contained in the section of this prospectus entitled Glossary of Selected Terms.

The executive compensation philosophy of the compensation committee is threefold:

- To align the executive officers interest with that of the stockholders and stakeholders, which provides long-term economic benefits to the stockholders;
- To provide competitive financial incentives in the form of salary, bonuses, and benefits with the goal of retaining and attracting talented and highly motivated executive officers; and
- To maintain a compensation program whereby the executive officers, through exceptional performance and equity ownership, will have the opportunity to realize economic rewards commensurate with appropriate gains of other equity holders and stakeholders.

The compensation committee reviews and makes recommendations to the board of directors regarding our overall compensation strategy and policies, with the full board of directors having the final authority on compensation matters. The board of directors may from time to time delegate to the compensation committee the authority to take actions on specific compensation matters or with respect to compensation matters for certain employees or officers. In the past, there has been no such delegation, but our board of directors may delegate to the compensation committee, for example, in order to comply with Section 16 of the Exchange Act or Section 162(m) of the Internal Revenue Code of 1986 when those laws require actions by outside or non-employee directors, as applicable. Rule 16b-3 issued under Section 16 of the Exchange Act provides that transactions between an issuer and its officers or directors involving issuer securities may be exempt from Section 16(b) of the Exchange Act if it meets certain requirements, one of which is approval by a committee of the board of directors of the issuer consisting of two or more non-employee directors. Section 162(m) of the Internal Revenue Code limits deductions by publicly held corporations for compensation paid to its covered employees (i.e., its chief executive officer and next four highest compensated officers) to the extent that the employee s compensation for the taxable year exceeds $1,000,000. This limit does not apply to qualified performance-based compensation , which requires, among other things, satisfaction of a performance goal that is established by a committee of the board of directors consisting of two or more outside directors.

The compensation committee (1) develops, approves and oversees policies relating to compensation of our chief executive officer and other executive officers, (2) discharges the board s responsibility relating to the establishment, amendment, modification, or termination of our 2007 Long Term Incentive Plan, the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) (the Phantom Unit Plan I) and the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) (the Phantom Unit Plan II), health and welfare plans, incentive plans, defined contribution plans (401(k) plans), and any other benefit plan, program or arrangement which we sponsor or maintain and (3) discharges the responsibilities of the override unit committee of the board of directors.

Specifically, the compensation committee reviews and makes recommendations to the board of directors regarding annual and long-term performance goals and objectives for the chief executive officer and our other senior executives; reviews and makes recommendations to the board of directors regarding the annual salary, bonus and other incentives and benefits, direct and indirect, of the chief executive officer and our senior executives; reviews and authorizes the company to enter into employment, severance or other compensation agreements with the chief executive officer and other senior executives; administers our executive incentive plans, including the Phantom Unit Plan I and the Phantom Unit Plan II; establishes and periodically reviews perquisites and fringe benefits policies; reviews annually the implementation of our company-wide incentive bonus program; oversees contributions to our 401(k) plan; and performs such duties and responsibilities as may be assigned by the board of directors to the compensation committee under the terms of any executive compensation plan, incentive compensation plan or equity-based plan and as may be assigned to the compensation committee with respect to the issuance and management of the override units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

The compensation committee has regularly scheduled meetings concurrent with the board of directors meetings and additionally meets at other times as needed throughout the year. Frequently issues are discussed via teleconferencing. The chief executive officer, while a member of the compensation committee prior to our becoming a public company, did not participate in the determination of his own compensation, thereby avoiding any potential conflict of interest. However, he actively provided and will continue to provide guidance and recommendations to the committee regarding the amount and form of the compensation of the other executive officers and key employees. During 2006 and prior to our becoming a public company, given that the compensation committee consisted of senior representatives of the Goldman Sachs Funds and the Kelso Funds, as well as our chief executive officer, the board did not change or reject decisions made by the compensation committee.

Compensation paid to executive officers is closely aligned with our performance on both a short-term and long-term basis. Compensation is structured competitively in order to attract, motivate and retain executive officers and key employees and is considered crucial to our long-term success and the long-term enhancement of stockholder value. Compensation is structured to ensure that the executive officers objectives and rewards are directly correlated to our long-term objectives and the executive officers interests are aligned with those of stockholders. To this end, the compensation committee believes that the most critical component of compensation is equity compensation.

The following discusses in detail the foundation underlying and the drivers of our executive compensation philosophy, and also how the related decisions are made. Qualitative information related to the most important factors utilized in the analysis of these decisions is described.

Elements of Compensation

The three primary components of the compensation program are salary, an annual cash incentive bonus, and equity awards. Executive officers are also provided with benefits that are generally available to our salaried employees.

While these three components are related, we view them as separate and analyze them as such. The compensation committee believes that equity compensation is the primary motivator in

Table of Contents

attracting and retaining executive officers. Salary and cash incentive bonuses are viewed as secondary; however, the compensation committee views a competitive level of salary and cash bonus as critical to retaining talented individuals.

Base Salary

We fix the base salary of each of our executive officers at a level that we believe enables us to hire, motivate and retain individuals in a competitive environment and to reward satisfactory individual and company performance. In determining its recommendations for salary levels, the compensation committee takes into account peer group pay and individual performance.

With respect to our peer group, management, through the chief executive officer, provides the compensation committee with information gathered through a detailed annual review of executive compensation programs of other publicly and privately held companies in our industry, which are similar to us in size and operations (among other factors). In 2007, management reviewed and provided information to the compensation committee regarding the salary, bonus and other compensation amounts paid to named executive officers in respect of 2006 for the following independent refining companies, which we view as members of our peer group: Frontier Oil Corporation, Holly Corporation and Tesoro Corporation. Management also reviewed the following fertilizer businesses for executives focused on our fertilizer business: CF Industries Holdings Inc. and Terra Industries, Inc. It then averaged these peer group salary levels over a number of years to develop a range of salaries of similarly situated executives of these companies, and used this range as a factor in determining base salary (and overall cash compensation) of the named executive officers. Management also reviewed the differences in levels of compensation among the named executive officers of this peer group, and used these differences as a factor in setting a different level of salary and overall compensation for each of our named executive officers based on their relative positions and levels of responsibility.

With respect to individual performance, the compensation committee considered, among other things, the following specific achievements over the past 12 months with respect to Mr. Lipinski.

Flood Response. Mr. Lipinski directed the Company s successful response to an unprecedented flood which devastated portions of the city of Coffeyville during the weekend of June 30, 2007 and closed down our refinery and the nitrogen fertilizer plant. The flood also resulted in a crude oil discharge from our refinery into the Verdigris River that required an immediate environmental response. Under Mr. Lipinski s leadership, the refinery was restored to full operation in approximately six weeks, and the fertilizer plant, situated on higher ground, returned to full operation in approximately 18 days. In addition, Mr. Lipinski oversaw our efforts to work closely with the EPA and Kansas and Oklahoma regulators to review and analyze the environmental effects of the crude oil discharge and coordinate a property repurchase project in which we purchased approximately 300 homes from citizens of Coffeyville at their pre-flood values (or greater). This effort contributed to a successful outcome in our defense of two class action lawsuits.

Initial Public Offering. Mr. Lipinski supervised the initial filing of our registration statement with the Securities and Exchange Commission in September 2006 and the consummation of our initial public offering in October 2007. The initial public offering process required a large amount of time and attention due to the turnaround in the first quarter of 2007, the decision to move our nitrogen fertilizer operations into a limited partnership structure, and the flood which occurred during the weekend of June 30, 2007. We ultimately listed our shares of common stock on the New York Stock Exchange and sold 23 million shares in the offering at an initial price of $19.00 per share.

Business Expansion. Mr. Lipinski directed the Company s growth strategy beginning in 2005, which included our refinery expansion project during 2006 and 2007 and the fertilizer plant UAN expansion project that commenced in 2007. Nearly every process unit at the refinery was involved in the refinery expansion project, which was consummated in the fourth quarter of

2007. Our refinery throughput rates, averaging less than 90,000 bpd prior to June 2005, averaged over 110,000 bpd of crude during the fourth quarter of 2007, a record rate for our refinery. In addition, the blend of crudes was optimized to accommodate larger volumes of heavy sour crude. We processed more than 21,000 bpd of heavy sour crude in the fourth quarter of 2007, as compared with 2,700 bpd of heavy sour crude in the first quarter of 2006. Part of this project also included the addition of a new 24,000 bpd continuous catalytic reforming (CCR) unit which replaced an older technology unit two-thirds its size. The new CCR increased reforming capacity and also over time will produce more hydrogen, which over time will reduce our refinery s dependence on the nitrogen fertilizer business for hydrogen purchases. The fertilizer plant UAN expansion project is expected to enable the nitrogen fertilizer plant to consume substantially all of its net ammonia production in the production of UAN, historically a higher margin product than ammonia. We estimate that it will result in an approximately 50% increase in the fertilizer plant s annual UAN production.

With respect to individual performance of Messrs. Riemann, Rens, Haugen and Daly, the compensation committee considered, among other things, management s immediate and effective response to the June 2007 flood, the successful completion of our initial public offering in October 2007 and the expansion of our refinery s capacity as evidenced by achievement of record throughput rates in the fourth quarter of 2007.

Each of the named executive officers has an employment agreement which sets forth his base salary. Salaries are reviewed annually by the compensation committee with periodic informal reviews throughout the year. Adjustments, if any, are usually made on January 1st of the year immediately following the review. In the fourth quarter of 2006, the compensation committee determined that Mr. Haugen s base salary should be increased from $225,000 to $275,000 due to his increased responsibilities with our Company. The base salaries of Mr. Lipinski, Mr. Riemann and Mr. Rens were not adjusted at that time. The compensation committee most recently reviewed the level of cash salary and bonus for each of the executive officers in November 2007 and noted certain changes of responsibilities and promotions. Individual performance, the practices of our peer group of companies and changes in an executive officer s status were considered, and each measurement was given relatively equal weight. The compensation committee recommended that the board of directors increase the 2008 salaries of Messrs. Lipinski (to $700,000 from $650,000), Riemann (to $375,000 from $350,000) and Rens (to $300,000 from $250,000), respectively, effective January 1, 2008, due to the increase in the cost of living and in order align their total compensation with compensation paid by companies in our peer group. Prior to October 23, 2007, Mr. Daly did not have an employment agreement with the Company. His base salary of $215,000 for 2007 was increased to $220,000 effective January 1, 2008 pursuant to the terms of the October 23, 2007 employment agreement. Mr. Haugen s salary for 2008 remained at $275,000.

In addition, the compensation committee determined that no equity awards should be made to the named executive officers in connection with our initial public offering in 2007. However, the compensation committee may elect to make restricted stock grants, option grants or other equity grants during 2008 in its discretion. In addition, Coffeyville Acquisition III LLC, which owns the managing general partner of the Partnership, made limited equity grants of interests in Coffeyville Acquisition III LLC to the executive officers in 2007.

Annual Bonus

We use information about total cash compensation paid by members of our peer group of companies, the composition of which is discussed above, in determining both the level of bonus award and the ratio of salary to bonus because we believe that maintaining a level of bonus and a ratio of fixed salary (which is fixed and guaranteed) to bonus (which may fluctuate) that is in line with those of our competitors is an important factor in retaining the executives. The compensation committee also desires that a significant portion of our executive officers compensation package be at risk. That is, a portion of the executive officers overall compensation would not be guaranteed and would be

184

Table of Contents

determined based on individual and company performance. With respect to individual performance, the compensation committee considered the specific achievements of our named executive officers, as described above.

Our program provides for greater potential bonus awards as the authority and responsibility of a position increase. Our chief executive officer has the greatest percentage of his compensation at risk in the form of a discretionary bonus. Bonuses are determined based on our analysis of the total compensation packages for executive officers in our peer group. Our named executive officers retain a significant percentage of their compensation package at risk in the form of potential discretionary bonuses.

Bonuses may be paid in an amount equal to the target percentage, less than the target percentage or greater than the target percentage based on current year performance as recommended by the compensation committee. The performance determination takes into account overall operational performance, financial performance, factors affecting shareholder value including growth initiatives, and the individual s personal performance. The determination of whether the target bonus amount should be paid is not based on specific metrics, but rather a general assessment of how the business performed as compared to the business plan developed for the year. Due to the nature of the business, financial performance alone may not dictate or be a fair indicator of the performance of the executive officers. Conversely, financial performance may exceed all expectations, but it could be due to outside forces in the industry rather than true performance by an executive that exceeds expectations. In order to take this mismatch into consideration and to assess the executive officers performance on their own merits, the compensation committee makes an assessment of the executive officer s performance separate from the actual financial performance of the company, although such measurement is not based on any specific metrics.

The compensation committee reviewed the individualized performance and company performance as compared to expectations for the year ended December 31, 2007. Under their employment agreements, the 2007 target bonuses were the following percentages of salary for each of the following: Mr. Lipinski (250%), Mr. Rens (120%), Mr. Riemann (200%), Mr. Haugen (120%) and Mr. Daly (80%). The bonuses in respect of 2007 performance were greater than target for Messrs. Lipinski and Rens due to their significant and continuous involvement in our initial public offering, which was consummated in October 2007, and due to their effective leadership role in and their coordination of the effective response to the flood that occurred during the weekend of June 30, 2007. Bonuses in respect of 2007 performance were less than target for Messrs. Riemann and Haugen because of a review of how the business performed as compared to our business plan developed for the year. Mr. Daly s bonus was approximately equivalent to his target bonus amount. Under their employment agreements, the 2008 target bonuses will be the following percentages of salary for each of the following: Mr. Lipinski (250%), Mr. Rens (120%), Mr. Riemann (200%), Mr. Haugen (120%) and Mr. Daly (80%).

Annual cash incentive bonuses for our named executive officers are established as part of their respective individual employment agreements. Each of these employment agreements provides that the executive will receive an annual cash performance bonus determined in the discretion of the board of directors, with a target bonus amount specified as a percentage of salary for that executive officer based on individualized performance goals and company performance goals. In connection with the review of peer company compensation practices with respect to total cash compensation paid as described above, in November 2007, the compensation committee did not adjust the future target percentage for the performance-based annual cash bonus for executive officers as the Committee felt such targets were comparable to, and appropriate with respect to, its peer companies.

Equity

We use equity incentives to reward long-term performance. The issuance of equity to executive officers is intended to generate significant future value for each executive officer if the company s

Table of Contents

performance is outstanding and the value of the company s equity increases for all stockholders. The compensation committee believes that this also promotes long-term retention of the executive. The equity incentives were negotiated to a large degree at the time of the acquisition of our business in June 2005 (with additional units that were not originally allocated in June 2005 issued in December 2006) in order to bring the executive officers compensation package in line with executives at private equity portfolio companies, based on the private equity market practices at that time.

The greatest share of total compensation to the chief executive officer and other named executive officers (as well as selected senior executives and key employees) is in the form of equity: common units in our two largest stockholders, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, override units within Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and common and override units in Coffeyville Acquisition III LLC, the entity which owns the managing general partner of the Partnership which holds the nitrogen fertilizer business. Any financial obligations related to such common units and override units reside with the issuer of such units and not with CVR Energy. Separately, Coffeyville Resources, LLC, a subsidiary of CVR Energy, issued phantom points to certain members of management, and any financial obligations related to such phantom points are the obligations of CVR Energy. The total number of such awards is detailed in this prospectus and was approved by the board of directors.

The limited liability company agreements of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC provide the methodology for payouts for most of this equity based compensation. In general terms, the agreements provide for two classes of interests in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC: (1) common units and (2) profits interests, which are called override units (and consist of both operating units and value units). Each of the named executive officers has a capital account under which his balance is increased or decreased to reflect his allocable share of net income and gross income of Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, the capital that the named executive officer contributed in exchange for his common units, distributions paid to such named executive officer and his allocable share of net loss and items of gross deduction. Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC may make distributions to their members to the extent that the cash available to them is in excess of the business reasonably anticipated needs. Distributions are generally made to members capital accounts in proportion to the number of units each member holds. All cash payable pursuant to the limited liability company agreements of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will be paid by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, respectively, and will not be paid by CVR Energy. Although CVR Energy is required to recognize a compensation expense with respect to such awards, CVR Energy also records a contribution to capital with respect to these awards, and as a result, there is no cash effect on CVR Energy.

The Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) (which we refer to as the Phantom Unit Plan I) works in correlation with the methodology established by the Coffeyville Acquisition LLC limited liability company agreement and the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) (which we refer to as the Phantom Unit Plan II) works in correlation with the methodology established by the Coffeyville Acquisition II LLC limited liability company agreement.

The limited liability company agreement of Coffeyville Acquisition III LLC provides for two classes of interests in Coffeyville Acquisition III LLC: (1) common units and (2) profits interests, which are called override units. Each of the named executive officers has a capital account under which his balance is increased or decreased to reflect his allocable share of net income and gross income of Coffeyville Acquisition III LLC, the capital that the named executive officer contributed, distributions paid to such named executive officer and his allocable share of net loss and items of gross deduction. Coffeyville Acquisition III LLC may make distributions to its members to the extent that the cash available to it is in excess of the business reasonably anticipated needs. Distributions are generally made to members capital accounts in proportion to the number of units each member holds.

Table of Contents

All issuances of override units and phantom points made through December 31, 2007 were made at what the board of directors determined to be their fair value on their respective grant dates. For a more detailed description of these plans, please see Executive Officers Interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC , Executive Officers Interests in Coffeyville Acquisition III LLC , and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) , below.

Additionally, there was a pool of override units under the Coffeyville Acquisition LLC limited liability company agreement that had not been issued as of December 2006. It was the intent that, upon a filing of a registration statement, the unallocated override units in the pool would be issued. The compensation committee recommended that all remaining override units in the pool available be issued to John J. Lipinski on December 29, 2006. The compensation committee made its decision and recommendation to the board of directors to grant Mr. Lipinski these additional units based on his accomplishments (and made the decision and recommendation without any input from Mr. Lipinski). Mr. Lipinski has been and will continue to be instrumental in positioning the company to become more competitive and in increasing the capacity of the refinery operations through his negotiating and obtaining favorable crude oil pricing, as well as in helping to gain access to capital in order to expand overall operations of both segments of our business. The increased value and growth of the business is directly attributable to the actions and leadership that Mr. Lipinski has provided for the overall executive management group.

Additionally, due to the significant contributions of Mr. Lipinski as reflected above, in December 2006 the compensation committee awarded him for his services 0.1044200 shares in Coffeyville Refining & Marketing, Inc. and 0.2125376 shares in Coffeyville Nitrogen Fertilizers, Inc. This approximated 0.31% and 0.64% of each company s total shares outstanding, respectively, at that time. The shares were issued to compensate him for his exceptional performance related to the operations of the business. In connection with the formation of Coffeyville Refining & Marketing Holdings, Inc. in August 2007, Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing, Inc. were exchanged for an equivalent number of shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. Prior to our becoming a public company in October 2007, these shares were exchanged for 247,471 shares of common stock in CVR Energy at an equivalent fair market value.

We also established a stock incentive plan in connection with our initial public offering in October 2007. No awards have been established at this time for the chief executive officer or other named executive officers. In keeping with the compensation committee s stated philosophy, such awards will be intended to help achieve the compensation goals necessary to run our business. As stated above, the compensation committee may elect to make awards under this plan in 2008 at its discretion.

Other Forms of Compensation

Each of our executive officers has a provision in his employment agreement providing for certain severance benefits in the event of termination without cause. These severance provisions are described in the Employment Agreements and Other Arrangements section below. The severance arrangements were all negotiated with the original employment agreements between the executive officer and the company. There are no change of control arrangements, but the compensation committee believed that there needed to be some form of compensation upon certain events of termination of services as is customary for similar companies.

As a general matter, we do not provide a significant number of perquisites to named executive officers.

Compensation Policies and Philosophy

Ours is a commodity business with high volatility and risk where earnings are not only influenced by margins, but also by unique, innovative and aggressive actions and business practices on the part of the executive team. The compensation committee routinely reviews financial and operational performance compared to our business plan, positive and negative industry factors, and the response of the senior management team in dealing with and maximizing operational and financial performance in the face of otherwise negative situations. Due to the nature of our business, performance of an individual or the business as a whole may be outstanding; however, our financial performance may not depict this same level of achievement. The financial performance of the company is not necessarily reflective of individual operational performance. These are some of the factors used in setting executive compensation. Specific performance levels or benchmarks are not necessarily used to establish compensation; however, the compensation committee takes into account all factors to make a subjective determination of related compensation packages for the executive officers.

The compensation committee has not adopted any formal or informal policies or guidelines for allocating compensation between long-term and current compensation, between cash and non-cash compensation, or among different forms of compensation other than its belief that the most crucial component is equity compensation. The decision is strictly made on a subjective and individual basis considering all relevant facts.

For compensation decisions, including decisions regarding the grant of equity compensation relating to executive officers (other than our chief executive officer and chief operating officer), the compensation committee typically considers the recommendations of our chief executive officer.

In recommending compensation levels and practices, our management reviews peer group compensation practices based on publicly available data. The analysis is done in-house in its entirety and is reviewed by executive officers who are not members of the compensation committee. The analysis is based on public information available through proxy statements and similar sources. Because the analysis is almost always performed based on prior year public information, it may often be somewhat outdated. We have not historically and at this time do not intend to hire or rely on independent consultants to analyze or prepare formal surveys for us. We do receive certain unsolicited executive compensation surveys; however, our use of these is limited as we believe we need to determine our baseline based on practices of other companies in our industry.

Because we are now a public company, Section 162(m) of the Internal Revenue Code limits the deductibility of compensation in excess of $1 million paid out to our executive officers unless specific and detailed criteria are satisfied. We believe that it is in our best interest to deduct compensation paid to our executive officers. We will consider the anticipated tax treatment to the company and our executive officers in the review and determination of the compensation payments and incentives. No assurance, however, can be given that the compensation will be fully deductible under Section 162(m).

Nitrogen Fertilizer Limited Partnership

A number of our executive officers, including our chief executive officer, chief operating officer, chief financial officer, general counsel, executive vice president/general manager for nitrogen fertilizer, and vice president, environmental, health and safety, serve as executive officers for both our company and the Partnership. These executive officers receive all of their compensation and benefits from us, including compensation related to services for the Partnership, and are not paid by the Partnership or its managing general partner. However, the Partnership or the managing general partner must reimburse us pursuant to a services agreement for the time our executive officers spend working for the Partnership. The percentage of each named executive officer s compensation that represents the services provided to the Partnership in 2007 are approximately as follows: John J. Lipinski (25%), Stanley A. Riemann (40%), James T. Rens (35%), Robert W. Haugen (5%) and Daniel J. Daly, Jr. (10%).

We have entered into a services agreement with the Partnership and its managing general partner in which we have agreed to provide management services to the Partnership for the operation of the nitrogen fertilizer business. Under this agreement, any of the Partnership, its managing general partner or Coffeyville Resources Nitrogen Fertilizers, LLC, a subsidiary of the Partnership, are required to pay

Table of Contents

us (i) all costs incurred by us in connection with the employment of our employees, other than administrative personnel, who provide services to the Partnership under the agreement on a full-time basis, but excluding share-based compensation; (ii) a prorated share of costs incurred by us in connection with the employment of our employees, other than administrative personnel, who provide services to the Partnership under the agreement on a part-time basis, but excluding share-based compensation, and such prorated share must be determined by us on a commercially reasonable basis, based on the percent of total working time that such shared personnel are engaged in performing services for the Partnership; (iii) a prorated share of certain administrative costs; and (iv) various other administrative costs in accordance with the terms of the agreement. Either we or the managing general partner of the Partnership may terminate the agreement upon at least 90 days notice.

Summary Compensation Table

The following table sets forth certain information with respect to compensation for the years ended December 31, 2006 and December 31, 2007 earned by our chief executive officer, our chief financial officer and our three other most highly compensated executive officers as of December 31, 2007. In this prospectus, we refer to these individuals as our named executive officers.

me and Principal Position	Year	Salary	Bonus(1)	Stock Awards(3)	Non-Equity Incentive Plan Compensation(1)(4)	All Other Compensation(5)	Total
n J. Lipinski	2007	$ 650,000	$ 1,850,000			$ 12,189,955(6)	$ 14,689,9
ef Executive Officer	2006	$ 650,000	$ 1,331,790	$ 4,326,188	$ 487,500	$ 5,007,935(7)	$ 11,803,4
es T. Rens	2007	$ 250,000	$ 400,000			$ 2,761,144(8)	$ 3,411,1
ef Financial Officer	2006	$ 250,000	$ 205,000		$ 130,000	$ 695,316(9)	$ 1,280,3
nley A. Riemann	2007	$ 350,000	$ 722,917(2)			$ 4,911,011(10)	$ 5,983,9
ef Operating Officer	2006	$ 350,000	$ 772,917(2)		$ 210,000	$ 943,789(11)	$ 2,276,7
ert W. Haugen	2007	$ 275,000	$ 230,000			$ 2,822,978(12)	$ 3,327,9
cutive Vice President, fining Operations	2006	$ 225,000	$ 205,000		$ 117,000	$ 695,471(13)	$ 1,242,4
niel J. Daly, Jr.	2007	$ 215,000	$ 200,000			$ 2,355,059(14)	$ 2,770,0
cutive Vice President, ategy	2006	$ 185,000	$ 175,000		$ 96,200	$ 714,705(15)	$ 1,170,9

(1) Bonuses are reported for the year in which they were earned, though they may have been paid the following year.

(2) Includes a retention bonus in the amount of $122,917.

(3) Reflects the amount recognized for financial statement reporting purposes for the fiscal years ended December 31, 2006 and December 31, 2007 with respect to shares of common stock of each of Coffeyville Refining & Marketing, Inc. and Coffeyville Nitrogen Fertilizers, Inc. granted to Mr. Lipinski effective December 28, 2006. In connection with the formation of Coffeyville Refining & Marketing Holdings, Inc. in August 2007, Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing, Inc. were exchanged for an equivalent number of shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. In connection with our initial public offering in October 2007, Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. were exchanged by Mr. Lipinski for 247,471 shares of our common stock.

(4) Reflects cash awards to the named individuals in respect of 2006 performance pursuant to our Variable Compensation Plan. Beginning in 2007, our executive officers no longer participated in this plan.

(5) The amounts shown represent grants of profits interests in Coffeyville Acquisition LLC, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC and grants of phantom points in Phantom Unit Plan I and Phantom Unit Plan II and reflect the dollar amounts recognized for financial statement reporting purposes for the years ended December 31, 2006 and December 31, 2007 in accordance with SFAS 123(R). For the 2006 amounts, assumptions used in the calculation are included in footnote 5 to our audited financial statements for the year ended December 31, 2006 included in the Company s registration statement on Form S-1/A filed on October 16, 2007. For

the 2007 amounts, assumptions used in the calculation are included in footnote 3 to our audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus. The profits interests in Coffeyville Acquisition LLC, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC and the phantom points in Phantom Unit Plan I and Phantom Unit Plan II are more fully described below under Executive Officers Interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC , Executive Officers Interests in Coffeyville Acquisition III LLC , and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) .

(6) Includes (a) a company contribution under our 401(k) plan in 2007, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2007, (c) the premiums paid for by us on behalf of the executive officer with respect to our basic life insurance program, (d) profits interests in Coffeyville Acquisition LLC that were granted in 2005 in the amount of $8,057,632, (e) profits interests in Coffeyville Acquisition LLC that were granted on December 29, 2006 in the amount of $1,595,428, (f) profits interests in Coffeyville Acquisition III LLC that were granted in October 2007 in the amount of $1,080 and (g) phantom points granted during the period ending December 31, 2006 in the amount of $2,519,640.

(7) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) forgiveness of a note that Mr. Lipinski owed to Coffeyville Acquisition LLC in the amount of $350,000, (d) forgiveness of accrued interest related to the forgiven note in the amount of $17,989, (e) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $630,059, (f) a cash payment in respect of taxes payable on his December 28, 2006 grant of subsidiary stock in the amount of $2,481,346, (g) profits interests in Coffeyville Acquisition LLC that were granted on December 29, 2006 in the amount of $20,510 and (h) phantom points granted during the period ending December 31, 2006 in the amount of $1,495,211.

(8) Includes (a) a company contribution under our 401(k) plan in 2007, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2007, (c) the premiums paid for by us on behalf of the executive officer with respect to our basic life insurance program, (d) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $1,836,087, (e) profits interests in Coffeyville Acquisition III LLC that were granted in October 2007 in the amount of $201 and (f) phantom points granted to Mr. Rens during the period ending December 31, 2006 in the amount of $911,768.

(9) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $279,670 and (d) phantom points granted to Mr. Rens during the period ending December 31, 2006 in the amount of $651,299.

(10) Includes (a) a company contribution under our 401(k) plan in 2007, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2007, (c) the premiums paid for by us on behalf of the executive officer with respect to our basic life insurance program (d) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $3,576,617, (e) profits interests in Coffeyville Acquisition III LLC that were granted in October 2007 in the amount of $393, (f) phantom points granted to Mr. Riemann during the period ending December 31, 2006 in the amount of $1,097,527 and (g) a relocation bonus of $222,099.

(11) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $143,571 and (d) phantom points granted to Mr. Riemann during the period ending December 31, 2006 in the amount of $541,061.

190

(12) Includes (a) a company contribution under our 401(k) plan in 2007, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2007, (c) the premiums paid for by us on behalf of the executive officer with respect to our basic life insurance program (d) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $1,836,087, (e) profits interests in Coffeyville Acquisition III LLC that were granted in October 2007 in the amount of $201, (f) phantom points granted to Mr. Haugen during the period ending December 31, 2006 in the amount of $911,768 and (g) a relocation bonus of $61,500.

(13) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $143,571 and (d) phantom points granted to Mr. Haugen during the period ending December 31, 2006 in the amount of $541,061.

(14) Includes (a) a company contribution under our 401(k) plan in 2007, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2007, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $1,324,168, (d) profits interests in Coffeyville Acquisition III LLC that were granted in October 2007 in the amount of $144 and (e) phantom points granted to Mr. Daly during the period ending December 31, 2006 in the amount of $1,016,972.

(15) Includes (a) a company contribution under our 401(k) plan in 2006, (b) the premiums paid by us on behalf of the executive officer with respect to our executive life insurance program in 2006, (c) profits interests in Coffeyville Acquisition LLC granted in 2005 in the amount of $103,543 and (d) phantom points granted to Mr. Daly during the period ending December 31, 2006 in the amount of $603,491.

Employment Agreements and Other Arrangements

Employment Agreements

John J. Lipinski. On July 12, 2005, Coffeyville Resources, LLC entered into an employment agreement with Mr. Lipinski, as Chief Executive Officer, which was subsequently assumed by CVR Energy and amended and restated effective as of December 29, 2007. The agreement has a rolling term of three years so that at the end of each month it automatically renews for one additional month, unless otherwise terminated by CVR Energy or Mr. Lipinski. Mr. Lipinski receives an annual base salary of $700,000. Mr. Lipinski is eligible to receive a performance-based annual cash bonus with a target payment equal to 250% of his annual base salary to be based upon individual and/or company performance criteria as established by our board of directors for each fiscal year.

Mr. Lipinski s agreement provides for certain severance payments that may be due following the termination of his employment. These benefits are described below under Potential Payments Upon Termination or Change-of-Control.

Stanley A. Riemann, James T. Rens, Robert W. Haugen and Daniel J. Daly, Jr. On July 12, 2005, Coffeyville Resources, LLC entered into employment agreements with each of Mr. Riemann, Mr. Rens, and Mr. Haugen. The agreements were subsequently assumed by CVR Energy and amended and rested effective as of December 29, 2007. The agreements have a term of three years and expire in December 2010, unless otherwise terminated earlier by the parties. CVR Energy entered into an employment agreement with Mr. Daly on October 23, 2007 and amended that agreement as of November 30, 2007. The agreements provide for an annual base salary of $375,000 for Mr. Riemann, $300,000 for Mr. Rens, $275,000 for Mr. Haugen and $220,000 for Mr. Daly. Each executive officer is eligible to receive a performance-based annual cash bonus to be based upon individual and/or company performance criteria as established by the board of directors of Coffeyville Resources, LLC for each fiscal year. The target annual bonus percentages are as follows: Mr. Riemann (200%), Mr. Rens (120%), Mr. Haugen (120%) and Mr. Daly (80%).

Table of Contents

These agreements provide for certain severance payments that may be due following the termination of the executive officers employment. These benefits are described below under Potential Payments Upon Termination or Change of Control .

Long Term Incentive Plan

The CVR Energy, Inc. 2007 Long Term Incentive Plan, or the LTIP, permits the grant of options, stock appreciation rights, or SARs, restricted stock, restricted stock units, dividend equivalent rights, share awards and performance awards (including performance share units, performance units and performance-based restricted stock). Individuals who are eligible to receive awards and grants under the LTIP include our and our subsidiaries employees, officers, consultants, advisors and directors. A summary of the principal features of the LTIP is provided below. As of December 31, 2007, no awards had been made under the LTIP to any of our executive officers.

Shares Available for Issuance. The LTIP authorizes a share pool of 7,500,000 shares of our common stock, 1,000,000 of which may be issued in respect of incentive stock options. Whenever any outstanding award granted under the LTIP expires, is canceled, is settled in cash or is otherwise terminated for any reason without having been exercised or payment having been made in respect of the entire award, the number of shares available for issuance under the LTIP shall be increased by the number of shares previously allocable to the expired, canceled, settled or otherwise terminated portion of the award. As of December 31, 2007, 7,463,600 shares of common stock were available for issuance under the LTIP.

Administration and Eligibility. The LTIP is administered by a committee, which is currently the compensation committee. The committee determines who is eligible to participate in the LTIP, determines the types of awards to be granted, prescribes the terms and conditions of all awards, and construes and interprets the terms of the LTIP. All decisions made by the committee are final, binding and conclusive.

Award Limits. In any three calendar year period, no participant may be granted awards in respect of more than 6,000,000 shares in the form of (i) stock options, (ii) SARs, (iii) performance-based restricted stock and (iv) performance share units, with the above limit subject to the adjustment provisions discussed below. The maximum dollar amount of cash or the fair market value of shares that any participant may receive in any calendar year in respect of performance units may not exceed $3,000,000.

Type of Awards. Below is a description of the types of awards available for grant pursuant to the LTIP.

Stock Options. The compensation committee is authorized to grant stock options to participants. The stock options may be either nonqualified stock options or incentive stock options. The exercise price of any stock option must be equal to or greater than the fair market value of a share on the date the stock option is granted. The term of a stock option cannot exceed 10 years (except that options may be exercised for up to 1 year following the death of a participant even, with respect to nonqualified stock options, if such period extends beyond the 10 year term). Subject to the terms of the LTIP, the option s terms and conditions, which include but are no limited to, exercise price, vesting, treatment of the award upon termination of employment, and expiration of the option, are determined by the committee and will be set forth in an award agreement. Payment for shares purchased upon exercise of an option must be made in full at the time of purchase. The exercise price may be paid (i) in cash or its equivalent (e.g., check), (ii) in shares of our common stock already owned by the participant, on terms determined by the committee, (iii) in the form of other property as determined by the committee, (iv) through participation in a cashless exercise procedure involving a broker or (v) by a combination of the foregoing.

SARs. The compensation committee may, in its discretion, either alone or in connection with the grant of an option, grant a SAR to a participant. The terms and conditions of the award will be set

192

Table of Contents

forth in an award agreement. SARs may be exercised at such times and be subject to such other terms, conditions, and provisions as the committee may impose. SARs that are granted in tandem with an option may only be exercised upon the surrender of the right to purchase an equivalent number of shares of our common stock under the related option and may be exercised only with respect to the shares of our common stock for which the related option is then exercisable. The committee may establish a maximum amount per share that would be payable upon exercise of a SAR. A SAR entitles the participant to receive, on exercise of the SAR, an amount equal to the product of (i) the excess of the fair market value of a share of our common stock on the date preceding the date of surrender over the fair market value of a share of our common stock on the date the SAR was issued, or, if the SAR is related to an option, the per-share exercise price of the option and (ii) the number of shares of our common stock subject to the SAR or portion thereof being exercised. Subject to the discretion of the committee, payment of a SAR may be made (i) in cash, (ii) in shares of our common stock or (iii) in a combination of both (i) and (ii).

Dividend Equivalent Rights. The compensation committee may grant dividend equivalent rights either in tandem with an award or as a separate award. The terms and conditions applicable to each dividend equivalent right would be specified in an award agreement. Amounts payable in respect of dividend equivalent rights may be payable currently or, if applicable, deferred until the lapsing of restrictions on the dividend equivalent rights or until the vesting, exercise, payment, settlement or other lapse of restrictions on the award to which the dividend equivalent rights relate.

Service Based Restricted Stock and Restricted Stock Units. The compensation committee may grant awards of time-based restricted stock and restricted stock units. Restricted stock and restricted stock units may not be sold, transferred, pledged or otherwise transferred until the time, or until the satisfaction of such other terms, conditions and provisions, as the committee may determine. When the period of restriction on restricted stock terminates, unrestricted shares of our common stock will be delivered. Unless the committee otherwise determines at the time of grant, restricted stock carries with it full voting rights and other rights as a stockholder, including rights to receive dividends and other distributions. At the time an award of restricted stock is granted, the committee may determine that the payment to the participant of dividends be deferred until the lapsing of the restrictions imposed upon the shares and whether deferred dividends are to be converted into additional shares of restricted stock or held in cash. The deferred dividends would be subject to the same forfeiture restrictions and restrictions on transferability as the restricted stock with respect to which they were paid. Each restricted stock unit represents the right of the participant to receive a payment upon vesting of the restricted stock unit or on any later date specified by the committee. The payment will equal the fair market value of a share of common stock as of the date the restricted stock unit was granted, the vesting date or such other date as determined by the committee at the time the restricted stock unit was granted. At the time of grant, the committee may provide a limitation on the amount payable in respect of each restricted stock unit. The committee may provide for a payment in respect of restricted stock unit awards (i) in cash or (ii) in shares of our common stock having a fair market value equal to the payment to which the participant has become entitled.

Share Awards. The compensation committee may award shares to participants as additional compensation for service to us or a subsidiary or in lieu of cash or other compensation to which participants have become entitled. Share awards may be subject to other terms and conditions, which may vary from time to time and among participants, as the committee determines to be appropriate.

Performance Share Units and Performance Units. Performance share unit awards and performance unit awards may be granted by the compensation committee under the LTIP. Performance share units are denominated in shares and represent the right to receive a payment in an amount based on the fair market value of a share on the date the performance share units were granted, become vested or any other date specified by the committee, or a percentage of such amount depending on the level of performance goals attained. Performance units are denominated in a specified dollar amount and represent the right to receive a payment of the specified dollar amount or a percentage of the specified dollar amount, depending on the level of performance goals attained.

193

Such awards would be earned only if performance goals established for performance periods are met. A minimum one-year performance period is required. At the time of grant the committee may establish a maximum amount payable in respect of a vested performance share or performance unit. The committee may provide for payment (i) in cash, (ii) in shares of our common stock having a fair market value equal to the payment to which the participant has become entitled or (iii) by a combination of both (i) and (ii).

Performance-Based Restricted Stock. The compensation committee may grant awards of performance-based restricted stock. The terms and conditions of such award will be set forth in an award agreement. Such awards would be earned only if performance goals established for performance periods are met. Upon the lapse of the restrictions, the committee will deliver a stock certificate or evidence of book entry shares to the participant. Awards of performance-based restricted stock will be subject to a minimum one-year performance cycle. At the time an award of performance-based restricted stock is granted, the committee may determine that the payment to the participant of dividends will be deferred until the lapsing of the restrictions imposed upon the performance-based restricted stock and whether deferred dividends are to be converted into additional shares of performance-based restricted stock or held in cash.

Performance Objectives. Performance share units, performance units and performance-based restricted stock awards under the LTIP may be made subject to the attainment of performance goals based on one or more of the following business criteria: (i) stock price; (ii) earnings per share; (iii) operating income; (iv) return on equity or assets; (v) cash flow; (vi) earnings before interest, taxes, depreciation and amortization, or EBITDA; (vii) revenues; (viii) overall revenue or sales growth; (ix) expense reduction or management; (x) market position; (xi) total stockholder return; (xii) return on investment; (xiii) earnings before interest and taxes, or EBIT; (xiv) net income; (xv) return on net assets; (xvi) economic value added; (xvii) stockholder value added; (xviii) cash flow return on investment; (xix) net operating profit; (xx) net operating profit after tax; (xxi) return on capital; (xxii) return on invested capital; or (xxiii) any combination, including one or more ratios, of the foregoing.

Performance criteria may be in respect of our performance, that of any of our subsidiaries, that of any of our divisions or any combination of the foregoing. Performance criteria may be absolute or relative (to our prior performance or to the performance of one or more other entities or external indices) and may be expressed in terms of a progression within a specified range. The compensation committee may, at the time performance criteria in respect of a performance award are established, provide for the manner in which performance will be measured against the performance criteria to reflect the effects of extraordinary items, gain or loss on the disposal of a business segment (other than the provisions for operating losses or income during the phase-out), unusual or infrequently occurring events and transactions that have been publicly disclosed, changes in accounting principles, the impact of specified corporate transactions (such as a stock split or stock dividend), special charges and tax law changes, all as determined in accordance with generally accepted accounting principles (to the extent applicable).

Amendment and Termination of the LTIP. Our board of directors has the right to amend the LTIP except that our board of directors may not amend the LTIP in a manner that would impair or adversely affect the rights of the holder of an award without the award holder s consent. In addition, our board of directors may not amend the LTIP absent stockholder approval to the extent such approval is required by applicable law, regulation or exchange requirement. The LTIP will terminate on the tenth anniversary of the date of stockholder approval. The board of directors may terminate the LTIP at any earlier time except that termination cannot in any manner impair or adversely affect the rights of the holder of an award without the award holder s consent.

Repricing of Options or SARs. Unless our stockholders approve such adjustment, the compensation committee will not have authority to make any adjustments to options or SARs that would

reduce or would have the effect of reducing the exercise price of an option or SAR previously granted under the LTIP.

Change in Control. The effect, if any, of a change in control on each of the awards granted under the LTIP may be set forth in the applicable award agreement.

Adjustments. In the event of a reclassification, recapitalization, merger, consolidation, reorganization, spin-off, split-up, stock dividend, stock split or reverse stock split, or similar transaction or other change in corporate structure affecting our common stock, adjustments and other substitutions will be made to the LTIP, including adjustments in the maximum number of shares subject to the LTIP and other numerical limitations. Adjustments will also be made to awards under the LTIP as the compensation committee determines appropriate. In the event of our merger or consolidation, liquidation or dissolution, outstanding options and awards will either be treated as provided for in the agreement entered into in connection with the transaction (which may include the accelerated vesting and cancellation of the options and SARs or the cancellation of options and SARs for payment of the excess, if any, of the consideration paid to stockholders in the transaction over the exercise price of the options or SARs), or converted into options or awards in respect of the same securities, cash, property or other consideration that stockholders received in connection with the transaction.

Executive Officers Interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC

The following is a summary of the material terms of the Coffeyville Acquisition LLC Second Amended and Restated Limited Liability Company Agreement and the Coffeyville Acquisition II LLC Agreement as they relate to the limited liability company interests granted to our named executive officers pursuant to those agreements as of December 31, 2007. We refer to the limited liability company agreements of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC collectively as the LLC Agreements. The terms of the two limited liability company agreements which relate to the interests granted to our named executive officers are identical to each other.

General. The LLC Agreements provide for two classes of interests in the respective limited liability companies: (i) common units and (ii) profits interests, which are called override units (which consist of both operating units and value units) (common units and override units are collectively referred to as units). The common units provide for voting rights and have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, as applicable. Such voting rights cease, however, if the executive officer holding common units ceases to provide services to Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, as applicable, or one of its or their subsidiaries. The common units were issued to our named executive officers in the following amounts (as subsequently adjusted) in exchange for capital contributions in the following amounts: Mr. Lipinski (capital contribution of $650,000 in exchange for 57,446 units), Mr. Riemann (capital contribution of $400,000 in exchange for 35,352 units), Mr. Rens (capital contribution of $250,000 in exchange for 22,095 units), Mr. Haugen (capital contribution of $100,000 in exchange for 8,838 units) and Mr. Daly (capital contribution of $50,000 in exchange for 4,419 units). These named executive officers were also granted override units, which consist of operating units and value units, in the following amounts: Mr. Lipinski (an initial grant of 315,818 operating units and 631,637 value units and a December 2006 grant of 72,492 operating units and 144,966 value units), Mr. Riemann (140,185 operating units and 280,371 value units), Mr. Rens (71,965 operating units and 143,931 value units), Mr. Haugen (71,965 operating units and 143,931 value units) and Mr. Daly (51,901 operating units and 103,801 value units). Override units have no voting rights attached to them, but have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable. Our named executive officers were not required to make any capital contribution with respect to the override units; override units were issued only to certain members of management who own common units and who agreed to provide services to Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable.

In addition, common units were issued to the following executive officers in the following amounts (as subsequently adjusted) in exchange for the following capital contributions: Mr. Kevan Vick (capital contribution of $250,000 in exchange for 22,095 units), Mr. Edmund Gross (capital contribution of $30,000 in exchange for 2,651 units), Mr. Christopher Swanberg (capital contribution of $25,000 in exchange for 2,209 units) and Mr. Wyatt Jernigan (capital contribution of $100,000 in exchange for 8,838 units). Also, Mr. Vick was granted 71,965 operating units and 143,931 value units and Mr. Jernigan was granted 71,965 operating units and 143,931 value units.

If all of the shares of common stock of our Company held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at $24.92 per share, which was the price of our common stock on June 16, 2008, and cash was distributed to members pursuant to the limited liability company agreements of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, our named executive officers would receive a cash payment in respect of their override units in the following approximate amounts: Mr. Lipinski ($66.0 million), Mr. Riemann ($25.7 million), Mr. Rens ($13.2 million), Mr. Haugen ($13.2 million), and Mr. Daly ($9.5 million).

Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC expect to distribute the proceeds of the sale of common stock in this offering to their members pursuant to their respective limited liability company agreements. Assuming the underwriters option to purchase additional shares is not exercised, if all of the shares of common stock of our Company to be sold in this offering by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at $24.92 per share, which was the price of our common stock on June 16, 2008, each of our named executive officers will receive a cash payment in respect of their override units in the following approximate amounts: Mr. Lipinski ($3.5 million), Mr. Riemann ($1.6 million), Mr. Rens ($0.9 million), Mr. Haugen ($0.7 million), and Mr. Daly ($0.5 million).

Forfeiture of Override Units Upon Termination of Employment. If the executive officer ceases to provide services to Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, or a subsidiary due to a termination for cause (as such term is defined in the LLC Agreements), the executive officer will forfeit all of his override units. If the executive officer ceases to provide services for any reason other than cause before the fifth anniversary of the date of grant of his operating units, and provided that an event that is an Exit Event (as such term is defined in the LLC Agreements) has not yet occurred and there is no definitive agreement in effect regarding a transaction that would constitute an Exit Event, then (a) unless the termination was due to the executive officer s death or disability (as that term is defined in the LLC Agreements), in which case a different vesting schedule will apply based on when the death or disability occurs, all value units will be forfeited and (b) a percentage of the operating units will be forfeited according to the following schedule: if terminated before the second anniversary of the date of grant, 100% of operating units are forfeited; if terminated on or after the second anniversary of the date of grant, but before the third anniversary of the date of grant, 75% of operating units are forfeited; if terminated on or after the third anniversary of the date of grant, but before the fourth anniversary of the date of grant, 50% of operating units are forfeited; and if terminated on or after the fourth anniversary of the date of grant, but before the fifth anniversary of the date of grant, 25% of his operating units are forfeited.

Adjustments to Capital Accounts; Distributions. Each of the executive officers has a capital account under which his balance is increased or decreased, as applicable, to reflect his allocable share of net income and gross income of Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, the capital that the executive officer contributed, distributions paid to such executive officer and his allocable share of net loss and items of gross deduction.

Value units owned by the executive officers do not participate in distributions under the LLC Agreements until the Current Value is at least two times the Initial Price (as these terms are defined in the LLC Agreements), with full participation occurring when the Current Value is four times the Initial Price and pro rata distributions when the Current Value is between two and four times the Initial Price. Coffeyville Acquisition LLC and Coffeyville

Acquisition II LLC may make distributions to their members to the extent that the cash available to them is in excess of the applicable business reasonably anticipated needs. Distributions are generally made to members capital accounts in proportion to the number of units each member holds. Distributions in respect of override units (both operating units and value units), however, will be reduced until the total reductions in proposed distributions in respect of the override units equals the Benchmark Amount (i.e., $11.31 for override units granted on July 25, 2005 and $34.72 for Mr. Lipinski s later grant). The boards of directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC will determine the Benchmark Amount with respect to each override unit at the time of its grant. There is also a catch-up provision with respect to any value unit that was not previously entitled to participate in a distribution because the Current Value was not at least four times the Initial Price.

Other Provisions Relating to Units. The executive officers are subject to transfer restrictions on their units, although they may make certain transfers of their units for estate planning purposes.

Executive Officers Interests in Coffeyville Acquisition III LLC

Coffeyville Acquisition III LLC, the sole owner of the managing general partner of the Partnership, is owned by the Goldman Sachs Funds, the Kelso Funds, our executive officers, Mr. Wesley Clark, Magnetite Asset Investors III L.L.C. and certain members of our senior management team. The following is a summary of the material terms of the Coffeyville Acquisition III LLC limited liability company agreement as they relate to the limited liability company interests held by our executive officers.

General. The Coffeyville Acquisition III LLC limited liability company agreement provides for two classes of interests in Coffeyville Acquisition III LLC: (i) common units and (ii) profits interests, which are called override units.

The common units provide for voting rights and have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition III LLC. Such voting rights cease, however, if the executive officer holding common units ceases to provide services to Coffeyville Acquisition III LLC or one of its subsidiaries. In October 2007, CVR Energy s executive officers made the following capital contributions to Coffeyville Acquisition III LLC and received a number of Coffeyville Acquisition III LLC common units equal to their pro rata portion of all contributions: Mr. Lipinski ($68,146), Mr. Riemann ($16,360), Mr. Rens ($10,225), Mr. Haugen ($4,090), Mr. Daly ($2,045), Mr. Jernigan ($4,090), Mr. Gross ($1,227), Mr. Vick ($10,225) and Mr. Swanberg ($1,022).

Override units have no voting rights attached to them, but have rights with respect to profits and losses of, and distributions from, Coffeyville Acquisition III LLC. The override units have the following terms:

Approximately 25% of all of the override units have been awarded to members of our management team. These override units automatically vested. These units will be owned by the members of our management team even if they no longer perform services for us or are no longer employed by us. The following executive officers received the following grants of this category of override units: Mr. Lipinski (81,250), Mr. Riemann (30,000), Mr. Rens (16,634), Mr. Haugen (16,634), Mr. Jernigan (14,374), Mr. Gross (8,786), Mr. Vick (13,405), Mr. Swanberg (8,786) and Mr. Daly (13,269).

Approximately 75% of the override units have been awarded to members of our management team responsible for the growth of the nitrogen fertilizer business. Some portion of these units may be awarded to members of management added in the future. These units vest on a five-year schedule, with 33.3% vesting on the third anniversary of the closing date of the Partnership s initial public offering (if any such offering occurs), an additional 33.4% vesting on the fourth anniversary of the closing date of such an offering, and the remaining 33.3% vesting on the fifth anniversary of the closing date of such an offering. Override units are entitled to distributions whether or not they have vested. Management members will forfeit unvested units if they are no longer employed by us; however, if a management member has three full years of service with the Partnership following the completion of an initial public offering of the

Table of Contents

Partnership, such management member may retire at age 62 and will be entitled to permanently retain all of his or her units whether or not they have vested pursuant to the vesting schedule described above. Units forfeited will be either retired or reissued to others (with a catchup payment provision); retired units will increase the unit values of all other units on a pro rata basis. The following executive officers received the following grants of this category of override units: Mr. Lipinski (219,378), Mr. Riemann (75,000), Mr. Rens (48,750), Mr. Haugen (13,125), Mr. Jernigan (11,250), Mr. Gross (22,500), Mr. Vick (45,000), Mr. Swanberg (11,250) and Mr. Daly (18,750).

The override units granted to management are entitled to 15% of all distributions made by Coffeyville Acquisition III LLC. All vested and unvested override units are entitled to distributions. To the extent that at any time not all override units have yet been granted, the override units that have been granted will be entitled to the full 15% of all distributions (e.g., if only 90% of the override units have been granted, the holders of these 90% are entitled to 15% of all distributions).

A portion of the override units may be granted in the future to new members of management. A catch up payment will be made to new members of management who receive units at a time when the current unit value has increased from the initial unit value.

The value of the common units and override units in Coffeyville Acquisition III LLC depends on the ability of the Partnership s managing general partner to make distributions. The managing general partner will not receive any distributions from the Partnership until the Partnership s aggregate adjusted operating surplus through December 31, 2009 has been distributed. Based on the Partnership s current projections, the Partnership believes that the executive officers will not begin to receive distributions on their common and override units until after December 31, 2010.

Adjustments to Capital Accounts; Distributions. Each of the executive officers has a capital account under which his balance is increased or decreased, as applicable, to reflect his allocable share of net income and gross income of Coffeyville Acquisition III LLC, the capital that the executive officer contributed, distributions paid to such executive officer and his allocable share of net loss and items of gross deduction.

Override units owned by the executive officers do not participate in distributions under the Coffeyville Acquisition III LLC limited liability company agreement until the Current Value is at least equal to the Initial Price (as these terms are defined in the Coffeyville Acquisition III LLC limited liability company agreement). Coffeyville Acquisition III LLC may make distributions to its members to the extent that the cash available to it is in excess of the business reasonably anticipated needs. Distributions are generally made to members capital accounts in proportion to the number of units each member holds. Distributions in respect of override units, however, will be reduced until the total reductions in proposed distributions in respect of the override units equals the aggregate capital contributions of all members.

Other Provisions Relating to Coffeyville Acquisition III LLC Units. The executive officers are subject to transfer restrictions on their Coffeyville Acquisition III LLC units, although they may make certain transfers of their units for estate planning purposes.

Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II)

The following is a summary of the material terms of the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I), or the Phantom Unit Plan I, and the Coffeyville Resources LLC Phantom Unit Appreciation Plan (Plan II), or the Phantom Unit Plan II, as they relate to our named executive officers. Payments under the Phantom Unit Plan I are tied to distributions made by Coffeyville Acquisition LLC, and payments under the Phantom Unit Plan II are tied to distributions made by Coffeyville Acquisition II LLC. We refer to the Phantom Unit Plan I and Phantom Unit Plan II collectively as the Phantom Unit Plans.

General. The Phantom Unit Plan I and Phantom Unit Plan II are administered by the compensation committees of the boards of directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II

LLC, as applicable. The Phantom Unit Plans provide for two classes of interests: phantom service points and phantom performance points (collectively referred to as phantom points). Holders of the phantom service points and phantom performance points have the opportunity to receive a cash payment when distributions are made pursuant to the LLC Agreements in respect of operating units and value units, respectively. The phantom points represent a contractual right to receive a payment when payment is made in respect of certain profits interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, as applicable.

Phantom points have been granted under each of the Phantom Unit Plans to our named executive officers in the following amounts: Mr. Lipinski (1,368,571 phantom service points and 1,368,571 phantom performance points, which represents approximately 14% of the total phantom points awarded), Mr. Riemann (596,133 phantom service points and 596,133 phantom performance points, which represents approximately 6% of the total phantom points awarded), Mr. Rens (495,238 phantom service points and 495,238 phantom performance points, which represents approximately 5% of the total phantom points awarded), Mr. Haugen (495,238 phantom service points and 495,238 phantom performance points, which represents approximately 5% of the total phantom points awarded) and Mr. Daly (552,381 phantom service points and 552,381 phantom performance points, which represents approximately 6% of the total phantom points awarded).

If all of the shares of common stock of our company held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at $24.92 per share, which was the closing price of our common stock on June 16, 2008, and cash was distributed to members pursuant to the LLC Agreement and the Coffeyville Acquisition II LLC Agreement, our named executive officers would receive a cash payment in respect of their phantom points in the following amounts: Mr. Lipinski ($8.8 million), Mr. Riemann ($3.8 million), Mr. Rens ($3.2 million), Mr. Haugen ($3.2 million) and Mr. Daly ($3.5 million). The compensation committees of the boards of directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC have authority to make additional awards of phantom points under the Phantom Unit Plans.

Assuming the underwriters option to purchase additional shares is not exercised, if all of the shares of common stock of our Company to be sold in this offering by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC were sold at $24.92 per share, which was the price of our common stock on June 16, 2008, each of our named executive officers will receive a cash payment in respect of their phantom points in the following approximate amounts: Mr. Lipinski ($0.5 million), Mr. Riemann ($0.2 million), Mr. Rens ($0.2 million), Mr. Haugen ($0.2 million), and Mr. Daly ($0.2 million).

Phantom Point Payments. Payments in respect of phantom service points will be made within 30 days from the date distributions are made pursuant to the LLC Agreements in respect of operating units. Cash payments in respect of phantom performance points will be made within 30 days from the date distributions are made pursuant to the LLC Agreements in respect of value units (i.e., not until the Current Value is at least two times the Initial Price (as such terms are defined in the LLC Agreements), with full participation occurring when the Current Value is four times the Initial Price and pro rata distributions when the Current Value is between two and four times the Initial Price). There is also a catch-up provision with respect to phantom performance points for which no cash payment was made because no distribution pursuant to the LLC Agreements was made with respect to value units.

Other Provisions Relating to the Phantom Points. The boards of directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC may, at any time or from time to time, amend or terminate the Phantom Unit Plans. If a participant s employment is terminated prior to an Exit Event (as such term is defined in the LLC Agreements), all of the participant s phantom points are forfeited. Phantom points are generally non-transferable (except by will or the laws of descent and distribution). If payment to a participant in respect of his phantom points would result in the application of the excise tax imposed under Section 4999 of the Internal Revenue Code of 1986, as amended, then the payment will be cut back only if that reduction would be more beneficial to the participant on an after-tax basis than if there were no reduction.

Table of Contents

Outstanding Equity Awards at 2007 Fiscal Year-End

	Stock Awards	
Name	Number of Shares or Units of Stock That Have Not Vested (#)(1)(2)	Market Value of Shares or Units of Stock That Have Not Vested ($)(3)
John J. Lipinski	118,431.7(4)	$ 6,139,499
	315,818.5(5)	$ 16,372,031
	36,246.0(6)	$ 1,878,993
	72,483.0(7)	$ 2,366,570
	118,431.7(8)	$ 6,139,499
	315,818.5(9)	$ 16,372,031
	36,246.0(10)	$ 1,878,993
	72,483(11)	$ 2,366,570
	1,368,571(12)	$ 1,241,568
	1,368,571(13)	$ 2,483,136
	1,368,571(14)	$ 1,241,568
	1,368,571(15)	$ 2,483,136
James T. Rens	26,986.9(16)	$ 1,399,001
	71,965.5(17)	$ 3,730,692
	26,986.9(18)	$ 1,399,001
	71,965.5(19)	$ 3,730,692
	495,238(20)	$ 449,271
	495,238(21)	$ 898,569
	495,238(22)	$ 449,271
	495,238(23)	$ 898,569
Stanley A. Riemann	52,569.4(24)	$ 2,725,198
	140,185.5(25)	$ 7,267,216
	52,569.4(26)	$ 2,725,198
	140,185.5(27)	$ 7,267,216
	596,133(28)	$ 540,821
	596,133(29)	$ 1,081,616
	596,133(30)	$ 540,821
	596,133(31)	$ 1,081,616
Robert W. Haugen	26,986.9(32)	$ 1,399,001
	71,965.5(33)	$ 3,730,692
	26,986.9(34)	$ 1,399,001
	71,965.5(35)	$ 3,730,692
	495,238(36)	$ 449,271
	495,238(37)	$ 898,569
	495,238(38)	$ 449,271
	495,238(39)	$ 898,569
Daniel J. Daly, Jr.	19,462.9(40)	$ 1,008,957
	51,900.5(41)	$ 2,690,522
	19,462.9(42)	$ 1,008,957
	51,900.5(43)	$ 2,690,522

552,381(44)	$	501,111
552,381(45)	$	1,002,249
552,381(46)	$	501,111
552,381(47)	$	1,002,249

200

(1) The profits interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC generally vest as follows: operating units generally become non-forfeitable in 25% annual increments beginning on the second anniversary of the date of grant, and value units are generally forfeitable upon termination of employment. The profits interests are more fully described above under Executive Officers Interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC .

(2) The phantom points granted pursuant to the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) are generally forfeitable upon termination of employment. The phantom points are more fully described above under Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) .

(3) The dollar amount shown reflects the fair value as of December 31, 2007, based upon an independent third-party valuation performed as of December 31, 2007 using the December 31, 2007 CVR Energy common stock closing price on the NYSE to determine the equity value of CVR Energy. Assumptions used in the calculation of these amounts are included in footnote 3 to the Company s audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus.

(4) Represents 118,431.7 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005. These operating units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(5) Represents 315,818.5 value units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005. These value units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(6) Represents 36,246.0 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on December 29, 2006. These operating units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(7) Represents 72,483.0 value units in Coffeyville Acquisition LLC deemed to be granted to the executive on December 29, 2006. These value units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(8) Represents 118,431.7 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on December 29, 2006. These operating units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(9) Represents 315,818.5 value units in Coffeyville Acquisition II LLC deemed to be granted to the executive on December 29, 2006. These value units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(10) Represents 36,246.0 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on December 29, 2006. These operating units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(11) Represents 72,483 value units in Coffeyville Acquisition II LLC deemed to be granted to the executive on December 29, 2006. These value units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(12) Represents 1,368,571 phantom service points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(13) Represents 1,368,571 phantom performance points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(14) Represents 1,368,571 phantom service points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(15) Represents 1,368,571 phantom performance points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(16) Represents 26,986.9 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(17) Represents 71,965.5 value units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(18) Represents 26,986.9 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(19) Represents 71,965.5 value units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(20) Represents 495,238 phantom service points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(21) Represents 495,238 phantom performance points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(22) Represents 495,238 phantom service points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(23) Represents 495,238 phantom performance points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(24) Represents 52,569.4 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(25) Represents 140,185.5 value units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(26) Represents 52,569.4 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(27) Represents 140,185.5 value units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(28) Represents 596,133 phantom service points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(29) Represents 596,133 phantom performance points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(30) Represents 596,133 phantom service points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(31) Represents 596,133 phantom performance points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(32) Represents 26,986.9 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(33) Represents 71,965.5 value units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(34) Represents 26,986.9 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(35) Represents 71,965.5 value units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(36) Represents 495,238 phantom service points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(37) Represents 495,238 phantom performance points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(38) Represents 495,238 phantom service points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(39) Represents 495,238 phantom performance points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(40) Represents 19,462.9 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(41) Represents 51,900.5 value units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(42) Represents 19,462.9 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(43) Represents 51,900.5 value units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(44) Represents 552,381 phantom service points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(45) Represents 552,381 phantom performance points under the Phantom Unit Plan I granted to the executive on December 11, 2006.

(46) Represents 552,381 phantom service points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

(47) Represents 552,381 phantom performance points under the Phantom Unit Plan II granted to the executive on December 11, 2006.

Equity Awards at 2007 Fiscal Year-End That Have Vested

	Stock Awards		
Name	**Number of Shares Acquired on Vesting (#)(1)(2)(3)**		**Value Realized on Vesting ($)(4)**
John J. Lipinski	39,477.3(5)	$	1,516,323
	39,477.3(6)	$	1,516,323
	53,921(7)	$	1,078
James T. Rens	8,995.6(8)	$	345,521
	8,995.6(9)	$	345,521
	10,066(10)	$	201
Stanley A. Riemann	17,523.1(11)	$	673,062
	17,523.1(12)	$	673,062
	19,650(13)	$	393
Robert W. Haugen	8,995.6(14)	$	345,521
	8,995.6(15)	$	345,521
	10,066(16)	$	201

Daniel J. Daly, Jr.	6,487.6(17)	$	249,189
	6,487.6(18)	$	249,189
	7,190(19)	$	144

(1) The profits interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC generally vest as follows: operating units generally become non-forfeitable in 25% annual increments beginning on the second anniversary of the date of grant, and value units are generally forfeitable upon termination of employment. The profits interests are more fully described above under Executive Officers Interests in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC .

(2) The profits interests in Coffeyville Acquisition III LLC described in this table were granted on October 24, 2007 and automatically vested on the date of grant, as more fully described above under Executive Officers Interests in Coffeyville Acquisition III LLC .

(3) The phantom points granted pursuant to the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and the Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) are generally forfeitable upon termination of employment. The phantom points are more fully described above under Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) .

(4) The dollar amounts shown are based on a valuation determined for purposes of SFAS 123(R) at the relevant vesting date of the respective override units.

(5) Represents 39,477.3 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005. These operating units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(6) Represents 39,477.3 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005. These operating units have been transferred to trusts for the benefit of members of Mr. Lipinski s family.

(7) Represents profits interests in Coffeyville Acquisition III LLC (53,921 override units) granted to the executive on October 24, 2007.

(8) Represents 8,995.6 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(9) Represents 8,995.6 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(10) Represents profits interests in Coffeyville Acquisition III LLC (10,066 override units) granted to the executive on October 24, 2007.

(11) Represents 17,523.1 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(12) Represents 17,523.1 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(13) Represents profits interests in Coffeyville Acquisition III LLC (19,650 override units) granted to the executive on October 24, 2007.

(14) Represents 8,995.6 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(15) Represents 8,995.6 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(16) Represents profits interests in Coffeyville Acquisition III LLC (10,066 override units) granted to the executive on October 24, 2007.

(17)

Represents 6,487.6 operating units in Coffeyville Acquisition LLC deemed to be granted to the executive on June 24, 2005.

(18) Represents 6,487.6 operating units in Coffeyville Acquisition II LLC deemed to be granted to the executive on June 24, 2005.

(19) Represents profits interests in Coffeyville Acquisition III LLC (7,190 override units) granted to the executive on October 24, 2007.

Potential Payments Upon Termination or Change of Control

Under the terms of their respective employment agreements, the named executive officers may be entitled to severance and other benefits following the termination of their employment. These benefits are summarized below. The amounts of potential post-employment payments assume that the triggering event took place on December 31, 2007.

If Mr. Lipinski s employment is terminated either by CVR Energy without cause and other than for disability or by Mr. Lipinski for good reason (as these terms are defined in Mr. Lipinski s employment agreement), then Mr. Lipinski is entitled to receive as severance (a) salary continuation for 36 months and (b) the continuation of medical benefits for thirty-six months at active-employee rates or until such time as Mr. Lipinski becomes eligible for medical benefits from a subsequent employer. The estimated total amounts of these payments are set forth in the table below. As a condition to receiving the salary continuation and continuation of medical benefits, Mr. Lipinski must (a) execute, deliver and not revoke a general release of claims and (b) abide by restrictive covenants as detailed below. If Mr. Lipinski s employment is terminated as a result of his disability, then in addition to any payments to be made to Mr. Lipinski under disability plan(s), Mr. Lipinski is entitled to supplemental disability payments equal to, in the aggregate, Mr. Lipinski s base salary as in effect immediately before his disability (the estimated total amount of this payment is set forth in the table below). Such supplemental disability payments will be made in installments for a period of 36 months from the date of disability. If Mr. Lipinski s employment is terminated at any time by reason of his death, then Mr. Lipinski s beneficiary (or his estate) will be paid the base salary Mr. Lipinski would have received had he remained employed through the remaining term of his contract. Notwithstanding the foregoing, CVR Energy may, at its option, purchase insurance to cover the obligations with respect to either Mr. Lipinski s supplemental disability payments or the payments due to Mr. Lipinski s beneficiary or estate by reason of his death. Mr. Lipinski will be required to cooperate in obtaining such insurance. If any payments or distributions due to Mr. Lipinski would be subject to the excise tax imposed under Section 4999 of the Internal Revenue Code of 1986, as amended, then such payments or distributions will be cut back only if that reduction would be more beneficial to him on an after-tax basis than if there were no reduction.

The agreement requires Mr. Lipinski to abide by a perpetual restrictive covenant relating to non-disclosure. The agreement also includes covenants relating to non-solicitation and non-competition during Mr. Lipinski s employment term and, following the end of term, for as long as he is receiving severance or supplemental disability payments or one year if he is receiving none.

If the employment of Mr. Riemann, Mr. Rens, Mr. Haugen or Mr. Daly is terminated either by CVR Energy without cause and other than for disability or by the executive officer for good reason (as such terms are defined in the respective employment agreements), then the executive officer is entitled to receive as severance (a) salary continuation for 12 months (18 months for Mr. Riemann) and (b) the continuation of medical benefits for 12 months (18 months for Mr. Riemann) at active-employee rates or until such time as the executive officer becomes eligible for medical benefits from a subsequent employer. The amount of these payments is set forth in the table below. As a condition to receiving the salary, the executives must (a) execute, deliver and not revoke a general release of claims and (b) abide by restrictive covenants as detailed below. The agreements provide that if any payments or distributions due to an executive officer would be subject to the excise tax imposed under Section 4999 of the Internal Revenue Code, as amended, then such payments or distributions will be cut back only if that reduction would be more beneficial to the executive officer on an after-tax basis than if there were no reduction.

The agreements require each of the executive officers to abide by a perpetual restrictive covenant relating to non-disclosure. The agreements also include covenants relating to non-solicitation and non-competition during their employment and, following termination of employment, for one year (for Mr. Riemann, the applicable period is during his employment and, following termination of employment, for as long as he is receiving severance, or one year if he is receiving none).

Table of Contents

Below is a table setting forth the estimated aggregate amount of the payments discussed above assuming a December 31, 2007 termination date (and, where applicable, no offset due to eligibility to receive medical benefits from a subsequent employer). The table assumes that the executive officers termination was by CVR Energy without cause or by the executive officers for good reason, and in the case of Mr. Lipinski also provides information assuming his termination was due to his disability.

Name	Total Severance Payments	Estimated Dollar Value of Medical Benefits
John J. Lipinski (severance if terminated without cause or resigns for good reason)	$ 1,950,000	$ 25,106
John J. Lipinski (supplemental disability payments if terminated due to disability)	$ 650,000	
Stanley A. Riemann (severance if terminated without cause or resigns for good reason)	$ 525,000	$ 12,553
James T. Rens (severance if terminated without cause or resigns for good reason)	$ 250,000	$ 11,998
Robert W. Haugen (severance if terminated without cause or resigns for good reason)	$ 275,000	$ 11,998
Daniel J. Daly, Jr. (severance if terminated without cause or resigns for good reason)	$ 215,000	$ 3,899

Equity Compensation Plan Information

The following table shows the total number of outstanding options and shares available for future issuances under our equity compensation plans as of December 31, 2007.

Plan Category	Number of Securities to Be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)
Equity Compensation Plans Approved by Security Holders	18,900	$ 21.61	7,463,600
Equity Compensation Plans Not Approved by Security Holders			
Total	18,900	$ 21.61	7,463,600

Table of Contents

Director Compensation for 2007

The following table provides compensation information for the year ended December 31, 2007 for each non-management director of our board.

Name	Fees Earned or Paid in Cash	Stock Awards(1)(2)	Option Awards(3)(4)(5)	All Other Compensation	Total
Wesley K. Clark*	$ 60,000			$ 449,290(6)	$ 509,290
Regis B. Lippert	$ 35,000	$ 11,885	$ 7,737		$ 54,662
Mark E. Tomkins	$ 75,000	$ 29,714	$ 7,737		$ 112,451
Scott L. Lebovitz, George E. Matelich, Stanley de J. Osborne and Kenneth A. Pontarelli					

* Wesley K. Clark, who was first elected to the board of Coffeyville Acquisition LLC in 2006, advised the board that due to his various outside interests and responsibilities he did not want to be nominated for reelection. Steve A. Nordaker replaced Mr. Clark on our board effective June 6, 2008.

(1) Mr. Lippert and Mr. Tomkins were awarded 5,000 and 12,500 shares of restricted stock, respectively, on October 22, 2007. The dollar amounts in the table reflect the dollar amounts recognized for financial statement reporting purposes for the fiscal year ended December 31, 2007 in accordance with SFAS 123(R). Assumptions used in these amounts are included in footnote 3 to the Company s audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus.

(2) The grant date fair value of stock awards granted during 2007, calculated in accordance with SFAS 123(R), was $104,400 for Mr. Lippert and $261,000 for Mr. Tomkins. Assumptions used in these amounts are included in footnote 3 to the Company s audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus.

(3) Mr. Lippert and Mr. Tomkins were awarded stock options in respect of (x) 5,150 shares each on October 22, 2007 and (y) 4,300 shares each on December 21, 2007. The amounts in the table reflect the dollar amount recognized for financial statement reporting purposes for the fiscal year ended December 31, 2007, in accordance with SFAS 123(R). Assumptions used in these amounts are included in footnote 3 to the Company s audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus.

(4) The grant date fair value of Mr. Lippert s and Mr. Tomkins option awards granted during 2007, calculated in accordance with FAS 123(R), was $117,881 for each director. Assumptions used in these amounts are included in footnote 3 to the Company s audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus.

(5) The aggregate number of shares subject to option awards outstanding on December 31, 2007 was 9,450 for each of Messrs. Lippert and Tomkins.

(6) Mr. Clark was awarded 244,038 phantom service points and 244,038 phantom performance points under the Coffeyville Resources, LLC Phantom Unit Plan (Plan I) in September 2005 for his services as a director. Collectively, Mr. Clark s phantom points represent 2.44% of the total phantom points awarded. The value of the interest was $71,234 on the grant date. In accordance with SFAS 123(R), we apply a fair-value-based measurement method in accounting for share-based issuance of the phantom points. An independent third-party valuation was performed as of December 31, 2007 using the December 31, 2007 CVR Energy common stock closing price on the NYSE to determine the equity value of CVR Energy. Assumptions used in the calculation of these amounts are included in footnote 3 to the Company s audited financial statements for the year ended December 31, 2007 included elsewhere in this prospectus. The phantom points are

Table of Contents

more fully described below under Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I) and Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) .

Non-employee directors who do not work principally for entities affiliated with us were entitled to receive an annual retainer of $60,000 for 2007. In addition, all directors are reimbursed for travel expenses and other out-of-pocket costs incurred in connection with their attendance at meetings. Effective January 1, 2007, Mark Tomkins joined our board of directors. Mr. Tomkins was elected as the chairman of the audit committee and in that role he receives an additional annual retainer of $15,000. Messrs. Lebovitz, Matelich, Osborne and Pontarelli received no compensation in respect of their service as directors in 2007.

In addition to the annual retainer described above, we granted to each of Mr. Tomkins and Mr. Lippert options to purchase 5,150 shares of CVR Energy with an exercise price equal to the initial public offering price ($19.00) on October 22, 2007. These options generally vest in one-third annual increments beginning on the first anniversary of the date of grant. We also granted 12,500 restricted shares of CVR Energy to Mr. Tomkins and 5,000 restricted shares of CVR Energy to Mr. Lippert on October 24, 2007. These shares of restricted stock generally vest in one-third annual increments beginning on the first anniversary of the date of grant, although the holder has the right to vote the shares whether or not they have vested. We also granted to each of Mr. Tomkins and Mr. Lippert options to purchase 4,300 shares of CVR Energy with an exercise price of $24.73 on December 21, 2007.

In connection with his election to our board of directors, we granted Mr. Nordaker options to purchase 4,350 shares of CVR Energy stock with an exercise price of $24.96 on June 10, 2008.

All grants were made pursuant to our 2007 Long Term Incentive Plan.

Table of Contents

PRINCIPAL AND SELLING STOCKHOLDERS

The following table presents information regarding beneficial ownership of our common stock by:

- each of our directors;
- each of our named executive officers;
- each stockholder known by us to beneficially hold five percent or more of our common stock;
- all of our executive officers and directors as a group; and
- all selling stockholders.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Unless indicated below, to our knowledge, the persons and entities named in the table have sole voting and sole investment power with respect to all shares beneficially owned, subject to community property laws where applicable. Shares of common stock subject to options that are currently exercisable or exercisable within 60 days of the date of this prospectus are deemed to be outstanding and to be beneficially owned by the person holding such options for the purpose of computing the percentage ownership of that person but are not treated as outstanding for the purpose of computing the percentage ownership of any other person. Except as otherwise indicated, the business address for each of our beneficial owners is c/o CVR Energy, Inc., 2277 Plaza Drive, Suite 500, Sugar Land, Texas 77479.

Beneficial Owner Name and Address	Shares Beneficially Owned prior to the offering		Number of Shares Offered	Shares Beneficially Owned after the offering	
	Number	Percent		Number	Percent
Coffeyville Acquisition LLC(1)	31,433,360	36.5%	4,977,500	26,455,860	30.7%
Kelso Investment Associates VII, L.P.(1)	31,433,360	36.5%	4,977,500	26,455,860	30.7%
KEP Fertilizer, LLC(1) 320 Park Avenue, 24th Floor New York, New York 10022	31,433,360	36.5%	4,977,500	26,455,860	30.7%
Coffeyville Acquisition II LLC(2)	31,433,360	36.5%	4,977,500	26,455,860	30.7%
The Goldman Sachs Group, Inc.(2) 85 Broad Street New York, New York 10004	31,433,360	36.5%	4,977,500	26,455,860	30.7%
John J. Lipinski(3)	247,471	*	45,000	202,471	*
Stanley A. Riemann(4)					
James T. Rens(5)					
Robert W. Haugen(6)	5,000	*		5,000	*
Daniel J. Daly, Jr.(7)					
Scott L. Lebovitz(2)	31,433,360	36.5%	4,977,500	26,455,860	30.7%

Regis B. Lippert(8)	7,500	*		7,500	*
George E. Matelich(1)	31,433,360	36.5%	4,977,500	26,455,860	30.7%
Steve A. Nordaker(9)					
Stanley de J. Osborne(1)	31,433,360	36.5%	4,977,500	26,455,860	30.7%
Kenneth A. Pontarelli(2)	31,433,360	36.5%	4,977,500	26,455,860	30.7%
Mark Tomkins(10)	12,500	*		12,500	*
All directors and executive officers, as a group (16 persons)(11)	63,145,691	73.3%	10,000,000	53,145,691	61.7%

Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC have granted the underwriters the option to purchase from them, on a pro rata basis, an aggregate of 1,500,000 additional shares. If the option to purchase additional shares were exercised in full, after the offering Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC would each own 25,705,860 shares, or 29.8%, of our common stock, and all of our directors and executive officers, as a group, would own 51,645,691 shares, or 60.0%, of our common stock.

* Less than 1%.

(1) Coffeyville Acquisition LLC directly owns 31,433,360 shares of common stock. Kelso Investment Associates VII, L.P. (KIA VII), a Delaware limited partnership, owns a number of common units in Coffeyville Acquisition LLC that corresponds to 24,557,883 shares of common stock, and KEP Fertilizer, LLC (KEP Fertilizer), a Delaware limited liability company, owns a number of common units in Coffeyville Acquisition LLC that corresponds to 6,081,000 shares of common stock. The Kelso Funds may be deemed to beneficially own indirectly, in the aggregate, all of the common stock of the Company owned by Coffeyville Acquisition LLC because the Kelso Funds control Coffeyville Acquisition LLC and have the power to vote or dispose of the common stock of the Company owned by Coffeyville Acquisition LLC. KIA VII and KEP Fertilizer, due to their common control, could be deemed to beneficially own each of the other s shares but each disclaims such beneficial ownership. Messrs. Nickell, Wall, Matelich, Goldberg, Bynum, Wahrhaftig, Berney, Loverro, Connors, Osborne and Moore may be deemed to share beneficial ownership of shares of common stock owned of record or beneficially owned by KIA VII, KEP Fertilizer and Coffeyville Acquisition LLC by virtue of their status as managing members of KEP Fertilizer and of Kelso GP VII, LLC, a Delaware limited liability company, the principal business of which is serving as the general partner of Kelso GP VII, L.P., a Delaware limited partnership, the principal business of which is serving as the general partner of KIA VII. Each of Messrs. Nickell, Wall, Matelich, Goldberg, Bynum, Wahrhaftig, Berney, Loverro, Connors, Osborne and Moore share investment and voting power with respect to the ownership interests owned by KIA VII, KEP Fertilizer and Coffeyville Acquisition LLC but disclaim beneficial ownership of such interests.

(2) Coffeyville Acquisition II LLC directly owns 31,433,360 shares of common stock. GS Capital Partners V Fund, L.P., GS Capital Partners V Offshore Fund, L.P., GS Capital Partners V GmbH & Co. KG and GS Capital Partners V Institutional, L.P. (collectively, the Goldman Sachs Funds) are members of Coffeyville Acquisition II LLC and own common units of Coffeyville Acquisition II LLC. The Goldman Sachs Funds common units in Coffeyville Acquisition II LLC correspond to 31,125,918 shares of common stock. The Goldman Sachs Group, Inc. and Goldman, Sachs & Co. may be deemed to beneficially own indirectly, in the aggregate, all of the common stock owned by Coffeyville Acquisition II LLC through the Goldman Sachs Funds because (i) affiliates of Goldman, Sachs & Co. and The Goldman Sachs Group, Inc. are the general partner, managing general partner, managing partner, managing member or member of the Goldman Sachs Funds and (ii) the Goldman Sachs Funds control Coffeyville Acquisition II LLC and have the power to vote or dispose of the common stock of the Company owned by Coffeyville Acquisition II LLC. Goldman, Sachs & Co. is a direct and indirect wholly owned subsidiary of The Goldman Sachs Group, Inc. Goldman, Sachs & Co. is the investment manager of certain of the Goldman Sachs Funds. Shares that may be deemed to be beneficially owned by the Goldman Sachs Funds consist of: (1) 16,389,665 shares of common stock that may be deemed to be beneficially owned by GS Capital Partners V Fund, L.P. and its general partner, GSCP V Advisors, L.L.C., (2) 8,466,218 shares of common stock that may be deemed to be beneficially owned by GS Capital Partners V Offshore Fund, L.P. and its general partner, GSCP V Offshore Advisors, L.L.C., (3) 5,620,242 shares of common stock that may be deemed to be beneficially owned by GS Capital Partners V Institutional, L.P. and its general partner, GSCP V Advisors, L.L.C., and (4) 649,793 shares of common stock that may be deemed to be beneficially owned by GS Capital Partners V GmbH & Co. KG and its general partner, Goldman, Sachs Management GP GmbH. Kenneth A. Pontarelli is a partner managing director of Goldman, Sachs & Co. and Scott L. Lebovitz is a managing director of Goldman, Sachs & Co. Mr. Pontarelli, Mr. Lebovitz, The Goldman Sachs Group, Inc. and Goldman, Sachs & Co. each disclaims beneficial ownership of the shares of common stock owned directly or indirectly by the Goldman Sachs Funds, except to the extent of their pecuniary interest therein, if any.

(3) Mr. Lipinski owns 247,471 shares of common stock directly. In addition, Mr. Lipinski owns 158,285 shares indirectly through his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Mr. Lipinski does not have the power to vote or dispose of shares that correspond to his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and thus does not have

beneficial ownership of such shares. Mr. Lipinski also owns (i) profits interests in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, (ii) phantom points under each of the Phantom Unit Plans and (iii) common units and override units in Coffeyville Acquisition III LLC. See Compensation Discussion and Analysis Outstanding Equity Awards at 2007 Fiscal Year-End and Compensation Discussion and Analysis Equity Awards at 2007 Fiscal Year-End That Have Vested . Such interests do not give Mr. Lipinski beneficial ownership of any shares of our common stock because they do not give Mr. Lipinski the power to vote or dispose of any such shares.

(4) Mr. Riemann owns no shares of common stock directly. Mr. Riemann owns 97,408 shares indirectly through his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Mr. Riemann does not have the power to vote or dispose of shares that correspond to his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and thus does not have beneficial ownership of such shares. Mr. Riemann also owns (i) profits interests in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, (ii) phantom points under each of the Phantom Unit Plans and (iii) common units and override units in Coffeyville Acquisition III LLC. See Compensation Discussion and Analysis Outstanding Equity Awards at 2007 Fiscal Year- End and Compensation Discussion and Analysis Equity Awards at 2007 Fiscal Year-End That Have Vested . Such interests do not give Mr. Riemann beneficial ownership of any shares of our common stock because they do not give Mr. Riemann the power to vote or dispose of any such shares.

(5) Mr. Rens owns no shares of common stock directly. Mr. Rens owns 60,879 shares indirectly through his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Mr. Rens does not have the power to vote or dispose of shares that correspond to his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and thus does not have beneficial ownership of such shares. Mr. Rens also owns (i) profits interests in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, (ii) phantom points under each of the Phantom Unit Plans and (iii) common units and override units in Coffeyville Acquisition III LLC. See Compensation Discussion and Analysis Outstanding Equity Awards at 2007 Fiscal Year-End and Compensation Discussion and Analysis Equity Awards at 2007 Fiscal Year-End That Have Vested . Such interests do not give Mr. Rens beneficial ownership of any shares of our common stock because they do not give Mr. Rens the power to vote or dispose of any such shares.

(6) Mr. Haugen owns 5,000 shares of common stock directly. Mr. Haugen owns 24,352 shares indirectly through his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Mr. Haugen does not have the power to vote or dispose of shares that correspond to his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and thus does not have beneficial ownership of such shares. Mr. Haugen also owns (i) profits interests in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, (ii) phantom points under each of the Phantom Unit Plans and (iii) common units and override units in Coffeyville Acquisition III LLC. See Compensation Discussion and Analysis Outstanding Equity Awards at 2007 Fiscal Year-End and Compensation Discussion and Analysis Equity Awards at 2007 Fiscal Year-End That Have Vested . Such interests do not give Mr. Haugen beneficial ownership of any shares of our common stock because they do not give Mr. Haugen the power to vote or dispose of any such shares.

(7) Mr. Daly owns no shares of common stock directly. Mr. Daly owns 12,176 shares indirectly through his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Mr. Daly does not have the power to vote or dispose of shares that correspond to his ownership of common units in Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and thus does not have beneficial ownership of such shares. Mr. Daly also owns (i) profits interests in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, (ii) phantom points under each of the Phantom Unit Plans and (iii) common units and override units in Coffeyville Acquisition III LLC. See Compensation Discussion and Analysis Outstanding Equity Awards at 2007 Fiscal Year-End and Compensation Discussion and Analysis Equity Awards at 2007 Fiscal Year-End That Have Vested . Such interests do not give Mr. Daly beneficial ownership of any shares of our common stock because they do not give Mr. Daly the power to vote or dispose of any such shares.

(8) In connection with our initial public offering, our board awarded 5,000 shares of non-vested restricted stock to Mr. Lippert. The date of grant for these shares of restricted stock was October 24, 2007. Under the terms of the

restricted stock agreement, Mr. Lippert has the right to vote his shares of restricted stock after the date of grant. However, the transfer restrictions on these shares will generally lapse in one-third annual increments beginning on the first anniversary of the date of grant. Because Mr. Lippert has the right to vote his non-vested shares of restricted stock, he is deemed to have beneficial ownership of such shares. In addition, our board awarded Mr. Lippert options to purchase 5,150 shares of common stock with an exercise price equal to the initial public offering price of our

Table of Contents

common stock, which was $19.00 per share. The date of grant for these options was October 22, 2007. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant. Additionally, our board awarded Mr. Lippert options to purchase 4,300 shares of common stock with an exercise price equal to the closing price of our common stock on the date of grant, which was $24.73. The date of grant for these options was December 21, 2007. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant. Additionally, members of Mr. Lippert s immediate family own 2,500 shares of our common stock directly. Mr. Lippert disclaims beneficial ownership of shares of our common stock owned by members of his immediate family.

(9) In connection with joining our board in June 2008, our board awarded Mr. Nordaker options to purchase 4,350 shares of common stock with an exercise price equal to the closing price of our common stock on the date of grant, which was $24.96. The date of grant for these options was June 10, 2008. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant.

(10) In connection with our initial public offering, our board awarded 12,500 shares of non-vested restricted stock to Mark Tomkins. The date of grant for these shares of restricted stock was October 24, 2007. Under the terms of the restricted stock agreement, Mr. Tomkins has the right to vote his shares of restricted stock after the date of grant. However, the transfer restrictions on these shares will generally lapse in one-third annual increments beginning on the first anniversary of the date of grant. Because Mr. Tomkins has the right to vote his non-vested shares of restricted stock, he is deemed to have beneficial ownership of such shares. In addition, our board awarded Mr. Tomkins options to purchase 5,150 shares of common stock with an exercise price equal to the initial public offering price of our common stock, which was $19.00 per share. The date of grant for these options was October 22, 2007. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant. Additionally, our board awarded Mr. Tomkins options to purchase 4,300 shares of common stock with an exercise price equal to the closing price of our common stock on the date of grant, which was $24.73. The date of grant for these options was December 21, 2007. These options will generally vest in one-third annual increments beginning on the first anniversary of the date of grant.

(11) The number of shares of common stock owned by all directors and executive officers, as a group, reflects the sum of (1) all shares of common stock directly owned by Coffeyville Acquisition LLC, with respect to which Messrs. George Matelich and Stanley de J. Osborne may be deemed to share beneficial ownership, (2) all shares of common stock directly owned by Coffeyville Acquisition II LLC, with respect to which Messrs. Kenneth A. Pontarelli and Scott L. Lebovitz may be deemed to share beneficial ownership, (3) the 247,471 shares of common stock owned directly by Mr. John J. Lipinski, the 1,000 shares of common stock owned directly by Mr. Gross, the 5,000 shares of common stock owned directly by Mr. Haugen, the 3,500 shares of common stock owned directly by Mr. Jernigan, the 1,000 shares of common stock owned directly by Mr. Vick and the 1,000 shares of common stock owned directly by Mr. Swanberg, (4) the 12,500 shares owned by Mr. Tomkins and (5) the 5,000 shares owned by Mr. Lippert and the 2,500 shares owned by members of Mr. Lippert s family.

Table of Contents

Distributions of the Proceeds of this Offering by Coffeyville Acquisition and Coffeyville Acquisition II

Coffeyville Acquisition and Coffeyville Acquisition II expect to distribute the proceeds of their sale of common stock in this offering to their members pursuant to their respective limited liability company agreements. If all of the shares of common stock of our Company to be sold in this offering by Coffeyville Acquisition and Coffeyville Acquisition II were sold at $24.92 per share, which was the price of our common stock on June 16, 2008, after giving effect to the underwriting discount, each of the entities and individuals named below would receive the following approximate amounts:

Entity / Individual	Distribution if Underwriters Option is not Exercised	Distribution if Underwriters Option is Exercised in Full
The Goldman Sachs Funds	$ 113,675,494	$ 130,345,080
The Kelso Funds	111,896,782	128,305,534
John J. Lipinski	3,488,826	4,270,538
Stanley A. Riemann	1,613,338	1,974,864
James T. Rens	871,197	1,062,613
Robert W. Haugen	749,569	921,423
Daniel J. Daly, Jr.	519,703	640,758
All executive officers, as a group	8,912,303	10,328,499
All management members, as a group	10,412,670	12,738,798
All other members, as a group	2,001,050	2,294,488

Payment to be made by the Company in respect of Phantom Points held by Our Named Executive Officers as a result of this Offering by Coffeyville Acquisition and Coffeyville Acquisition II

If all of the shares of common stock of our Company to be sold in this offering by Coffeyville Acquisition and Coffeyville Acquisition II were sold at $24.92 per share, which was the price of our common stock on June 16, 2008, after giving effect to the underwriting discount, each of the individuals named below would receive the following approximate amounts from the Company pursuant to the Phantom Unit Plans:

Individual	Distribution if Underwriters Option is not Exercised	Distribution if Underwriters Option is Exercised in Full
John J. Lipinski	$ 485,111	$ 590,816
Stanley A. Riemann	211,312	257,356
James T. Rens	175,541	213,792
Robert W. Haugen	175,541	213,792
Daniel J. Daly, Jr.	195,796	238,461
All executive officers, as a group	2,181,226	2,656,515
All management members, as a group	3,488,382	4,248,501
All other members, as a group	56,228	68,480

Table of Contents

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

This section describes related party transactions between CVR Energy (and its predecessors) and its directors, executive officers and 5% stockholders. For a description of transactions between CVR Energy and the Partnership, whose managing general partner is owned by our controlling stockholders and senior management, see The Nitrogen Fertilizer Limited Partnership.

Transactions with the Goldman Sachs Funds and the Kelso Funds

Investments in Coffeyville Acquisition LLC

Prior to our initial public offering in October 2007, GS Capital Partners V Fund, L.P. and related entities, or the Goldman Sachs Funds, and Kelso Investment Associates VII, L.P. and related entity, or the Kelso Funds, were the majority owners of Coffeyville Acquisition LLC. Other members of Coffeyville Acquisition LLC were John J. Lipinski, Stanley A. Riemann, James T. Rens, Edmund Gross, Robert W. Haugen, Wyatt E. Jernigan, Kevan A. Vick, Christopher Swanberg, Wesley Clark, Magnetite Asset Investors III L.L.C. and other members of our management team.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, between Coffeyville Group Holdings, LLC and Coffeyville Acquisition LLC, Coffeyville Acquisition LLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. The Goldman Sachs Funds made capital contributions of $112,817,500 to Coffeyville Acquisition LLC and the Kelso Funds made capital contributions of $110,817,500 to Coffeyville Acquisition LLC in connection with the acquisition. The total proceeds received by Pegasus Partners II, L.P. and the other unit holders of Coffeyville Group Holdings, LLC, including then current management, in connection with the Subsequent Acquisition was $526,185,017, after repayment of Immediate Predecessor s credit facility.

Coffeyville Acquisition LLC paid companies related to the Goldman Sachs Funds and the Kelso Funds each equal amounts totaling $6.0 million for the transaction fees related to the Subsequent Acquisition, as well as an additional $0.7 million paid to the Goldman Sachs Funds for reimbursed expenses related to the Subsequent Acquisition.

On July 25, 2005, the following executive officers and directors made the following capital contributions to Coffeyville Acquisition LLC: John J. Lipinski, $650,000; Stanley A. Riemann, $400,000; James T. Rens, $250,000; Kevan A. Vick, $250,000; Robert W. Haugen, $100,000; Wyatt E. Jernigan, $100,000; Chris Swanberg, $25,000. On September 12, 2005, Edmund Gross made a $30,000 capital contribution to Coffeyville Acquisition LLC. On September 20, 2005, Wesley Clark made a $250,000 capital contribution to Coffeyville Acquisition LLC. All but two of the executive officers received common units, operating units and value units of Coffeyville Acquisition LLC and the director received common units of Coffeyville Acquisition LLC.

On September 14, 2005, the Goldman Sachs Funds and the Kelso Funds each invested an additional $5.0 million in Coffeyville Acquisition LLC. On May 23, 2006, the Goldman Sachs Funds and the Kelso Funds each invested an additional $10.0 million in Coffeyville Acquisition LLC. In each case they received additional common units of Coffeyville Acquisition LLC.

On December 28, 2006, the directors of Coffeyville Acquisition LLC approved a cash dividend of $244,710,000 to companies related to the Goldman Sachs Funds and the Kelso Funds and $3,360,393 to certain members of our management team, including John J. Lipinski ($914,844), Stanley A. Riemann ($548,070), James T. Rens ($321,180), Kevan A. Vick ($321,180), Robert W. Haugen ($164,680) and Wyatt E. Jernigan ($164,680), as well as Wesley Clark

($241,205).

Split of Coffeyville Acquisition LLC

As part of the restructuring transactions that occurred immediately prior to our initial public offering, Coffeyville Acquisition LLC redeemed all of its outstanding common units held by the Goldman Sachs Funds in exchange for the same number of common units in Coffeyville Acquisition II LLC, a newly formed limited liability company to which Coffeyville Acquisition LLC transferred half of its interests in each of Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Nitrogen Fertilizers, Inc. and CVR Energy. In addition, half of the common units and override units in Coffeyville Acquisition

LLC held by each executive officer and Wesley Clark were redeemed in exchange for an equal number of common units and override units in Coffeyville Acquisition II LLC. As a result of these restructuring transactions, the Kelso Funds became the majority owner of Coffeyville Acquisition LLC and the Goldman Sachs Funds became the majority owner of Coffeyville Acquisition II LLC, and management and Wesley Clark retained an equivalent interest in each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

Stockholders Agreement

In October 2007, we entered into a stockholders agreement with Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. Pursuant to the agreement, for so long as Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC collectively beneficially own in the aggregate an amount of our common stock that represents at least 40% of our outstanding common stock, Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC each have the right to designate two directors to our board of directors so long as that party holds an amount of our common stock that represents 20% or more of our outstanding common stock and one director to our board of directors so long as that party holds an amount of our common stock that represents less than 20% but more than 5% of our outstanding common stock. If Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC cease to collectively beneficially own in the aggregate an amount of our common stock that represents at least 40% of our outstanding common stock, the foregoing rights become a nomination right and the parties to the stockholders agreement are not obligated to vote for each other s nominee. In addition, the stockholders agreement contains certain tag-along rights with respect to certain transfers (other than underwritten offerings to the public) of shares of common stock by the parties to the stockholders agreement. For so long as Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC beneficially own in the aggregate at least 40% of our common stock, (i) each such stockholder that has the right to designate at least two directors will have the right to have at least one of its designated directors on any committee (other than the audit committee and conflicts committee), to the extent permitted by SEC or NYSE rules, (ii) directors designated by the stockholders will be a majority of each such committee (at least 50% in the case of the compensation committee and the nominating committee), and (iii) the chairman of each such committee will be a director designated by such stockholder.

Registration Rights Agreements

In October 2007 we entered into a registration rights agreement with Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC pursuant to which we may be required to register the sale of our shares held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC and permitted transferees. Under the registration rights agreement, the Goldman Sachs Funds and the Kelso Funds each have the right to request that we register the sale of shares held by Coffeyville Acquisition LLC or Coffeyville Acquisition II LLC, as applicable, on their behalf on three occasions including requiring us to make available shelf registration statements permitting sales of shares into the market from time to time over an extended period. In addition, the Goldman Sachs Funds and the Kelso Funds have the ability to exercise certain piggyback registration rights with respect to their own securities if we elect to register any of our equity securities. The registration rights agreement also includes provisions dealing with holdback agreements, indemnification and contribution, and allocation of expenses. All of our shares held by Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC are entitled to these registration rights.

Dividend

In connection with our initial public offering in October 2007, the directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, respectively, approved a special dividend of approximately $10.6 million to their members, including $5,227,584 to the Goldman Sachs Funds, $5,145,787 to the Kelso Funds, $81,798 to Magnetite Asset Investors III L.L.C. and $103,269 to certain members of our senior management team and Wesley K. Clark. The common unitholders receiving this special dividend then contributed approximately $10.6 million collectively to

Coffeyville

Table of Contents

Acquisition III LLC, which used such amounts to acquire CVR GP, LLC, the managing general partner of the Partnership, from us.

J. Aron & Company

In June 2005 Coffeyville Acquisition LLC entered into commodity derivative contracts in the form of three swap agreements for the period from July 1, 2005 through June 30, 2010 with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. (the Cash Flow Swap). These agreements were assigned to Coffeyville Resources, LLC, a subsidiary of the Company, on June 24, 2005. Based on crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods July 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility (the Credit Facility), upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of expected crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010, so long as at the time of reduction or termination, we pay the amount of unrealized losses associated with the amount reduced or terminated. The Cash Flow Swap has resulted in unrealized gains (losses) of approximately $(235.9) million, $126.8 million and $(103.2) million for the years ended December 31, 2005, 2006 and 2007, respectively. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Derivative Instruments and Fair Value of Financial Instruments and Description of Our Indebtedness and the Cash Flow Swap Cash Flow Swap .

As a result of the flood and the temporary cessation of our Company s operations on June 30, 2007, Coffeyville Resources, LLC was required to enter into several deferral agreements with J. Aron with respect to the Cash Flow Swap. These deferral agreements deferred to August 31, 2008 the payment of approximately $123.7 million (plus accrued interest) which we owed to J. Aron. We are required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts.

During 2007 we were party to a crude oil supply agreement with J. Aron. On December 31, 2007, we entered into an amended and restated crude oil supply agreement with J. Aron. The terms of the agreement provide that we will obtain all of the crude oil for our refinery through J. Aron, other than crude oil that we acquire in Kansas, Missouri, Oklahoma, Wyoming and all states adjacent thereto. Pursuant to the agreement, we identify crude oil and pricing terms that meet our requirements and from time to time notify J. Aron of sourcing opportunities that we deem acceptable. We and/or J. Aron negotiate the cost of each barrel of crude oil that is purchased from third party crude oil suppliers. J. Aron executes all third party sourcing transactions and provides transportation and other logistical services for the crude oil it delivers to us. We generally pay J. Aron a fixed supply service fee per barrel over the negotiated cost of each barrel of crude oil purchased. In some cases, J. Aron will sell crude oil directly to us without having executed a specific third party sourcing transaction.

Coffeyville Acquisition LLC also entered into certain crude oil, heating oil and gasoline option agreements with J. Aron as of May 16, 2005. These agreements expired unexercised on June 16, 2005 and resulted in an expense of $25,000,000 reported in the accompanying consolidated statements of operations as a gain (loss) on derivatives for the 233 days ended December 31, 2005.

As a result of the refinery turnaround in early 2007, we needed to delay the processing of quantities of crude oil that we purchased from various small independent producers. In order to facilitate this anticipated delay, we entered into a purchase, storage and sale agreement for gathered crude oil, dated March 20, 2007, with J. Aron. Pursuant to the terms of the agreement, J. Aron agreed to purchase gathered crude oil from us, store the gathered crude oil and sell us the gathered crude oil on a forward basis. This agreement is no longer in effect.

Consulting and Advisory Agreements

Under the terms of separate consulting and advisory agreements, dated June 24, 2005, between Coffeyville Acquisition LLC and each of Goldman, Sachs & Co. and Kelso & Company, L.P., Coffeyville

216

Acquisition LLC was required to pay an advisory fee of $1,000,000 per year, payable quarterly in advance, to each of Goldman Sachs and Kelso for consulting and advisory services provided by Goldman Sachs and Kelso. Payments relating to the consulting and advisory agreements include $1,310,416, $2,315,937 and $1,703,990 which was expensed in selling, general, and administrative expenses for the 233 days ended December 31, 2005, the year ended December 31, 2006 and the year ended December 31, 2007, respectively. These agreements were terminated in connection with our initial public offering in October 2007 and each of Goldman, Sachs & Co. and Kelso & Company, L.P. received a one-time fee of $5 million by reason of such termination in conjunction with the offering.

Credit Facilities

Goldman Sachs Credit Partners L.P., an affiliate of Goldman, Sachs & Co., or Goldman Sachs, is one of the lenders under the Credit Facility. Goldman Sachs Credit Partners is also a joint lead arranger and bookrunner under the Credit Facility. In addition, Goldman Sachs Credit Partners L.P. was the sole arranger and sole bookrunner of the $25.0 million secured facility, the $25.0 million unsecured facility, and the $75.0 million unsecured facility, each of which was terminated in connection with the consummation of our initial public offering in October 2007. Goldman Sachs Credit Partners was also a lender, sole lead arranger, sole bookrunner and syndication agent under our first lien credit agreement and a lender and joint lead arranger, joint bookrunner and syndication agent under our second lien credit agreement. The first lien credit agreement and second lien credit agreement were entered into in connection with the acquisition of Coffeyville Group Holdings, LLC and its subsidiaries by Coffeyville Acquisition LLC in June 2005. At that time, we paid this Goldman Sachs affiliate a $22.1 million fee included in deferred financing costs. In conjunction with the financing that occurred on December 28, 2006, we paid approximately $8.1 million to a Goldman Sachs affiliate. Additionally, in conjunction with entering into the $25.0 million secured facility, the $25.0 million unsecured facility, and the $75.0 million unsecured facility on August 23, 2007, we paid approximately $1.3 million in fees and associated expense reimbursement to a Goldman Sachs affiliate. For the 233 days ended December 31, 2005, Successor made interest payments to this Goldman Sachs affiliate of $1.8 million recorded in interest expense and paid letter of credit fees of approximately $155,000 which were recorded in selling, general, and administrative expenses. See Description of Our Indebtedness and the Cash Flow Swap .

Guarantees

During 2007 one of the Goldman Sachs Funds and one of the Kelso Funds each guaranteed 50% of our payment obligations under the Cash Flow Swap in the amount of $123.7 million, plus accrued interest. These guarantees remain in effect as of the date of this prospectus.

In addition, in August 2007 these funds also guaranteed our obligations under the $25.0 million secured facility, the $25.0 million unsecured facility and the $75.0 million unsecured facility. These guarantees were terminated when the credit facilities were repaid and terminated in connection with the consummation of our initial public offering in October 2007.

Initial Public Offering and Convertible Senior Notes Offering

Goldman, Sachs & Co. was the lead underwriter of our initial public offering in October 2007. Goldman, Sachs & Co. was paid a customary underwriting discount for serving as underwriter. Goldman, Sachs & Co. is also the lead underwriter for our concurrent offering of $125 million aggregate principal amount of Convertible Senior Notes due 2013.

Secondary Offering

Coffeyville Acquisition and Coffeyville Acquisition II expect to distribute the proceeds of their sale of common stock in this offering to their members pursuant to their respective limited liability company agreements. The Kelso Funds are the principal owners of Coffeyville Acquisition, and the Goldman Sachs Funds are the principal owners of Coffeyville Acquisition II. Members of our senior management team own interests in both Coffeyville Acquisition and Coffeyville Acquisition II and will receive proceeds from the sale of shares of our common stock by Coffeyville Acquisition and Coffeyville Acquisition II. See Principal and Selling Stockholders .

Transactions with Directors and Senior Management

On June 30, 2005, Coffeyville Acquisition LLC loaned $500,000 to John J. Lipinski, CEO of Successor. This loan accrued interest at the rate of 7% per year. The loan was made in conjunction with Mr. Lipinski s purchase of 50,000 common units of Coffeyville Acquisition LLC. Mr. Lipinski repaid $150,000 of principal and paid $17,643.84 in interest on January 13, 2006. The unpaid loan balance of $350,000, together with accrued and unpaid interest of $17,989, was forgiven in full in September 2006.

On December 28, 2006, the directors of Coffeyville Nitrogen Fertilizers, Inc. approved the issuance of shares of common stock of Coffeyville Nitrogen Fertilizers, Inc., par value $0.01 per share, to John J. Lipinski in exchange for $10.00 pursuant to a Subscription Agreement. Mr. Lipinski also entered into a Stockholders Agreement with Coffeyville Nitrogen Fertilizers, Inc. and Coffeyville Acquisition LLC at the same time he entered into the Subscription Agreement. Pursuant to the Stockholders Agreement, among other things, Coffeyville Acquisition LLC had the right to exchange all shares of common stock in Coffeyville Nitrogen Fertilizers, Inc. held by Mr. Lipinski for such number of common units of Coffeyville Acquisition LLC or equity interests of a wholly-owned subsidiary of Coffeyville Acquisition LLC, in each case having a fair market value equal to the fair market value of the common stock in Coffeyville Nitrogen Fertilizers, Inc. held by Mr. Lipinski.

On December 28, 2006, the directors of Coffeyville Refining & Marketing, Inc. approved the issuance of shares of common stock of Coffeyville Refining & Marketing, Inc., par value $0.01 per share, to John J. Lipinski in exchange for $10.00 pursuant to a Subscription Agreement. Mr. Lipinski entered into a stockholders agreement with Coffeyville Refining & Marketing, Inc. similar to the agreement he entered into with Coffeyville Nitrogen Fertilizers, Inc.

In August 2007, Mr. Lipinski s shares of common stock in Coffeyville Refining & Marketing, Inc. were exchanged for an equivalent number of shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. Mr. Lipinski also entered into a Stockholders Agreement with Coffeyville Refining & Marketing Holdings, Inc. and Coffeyville Acquisition LLC at the time of the exchange. Pursuant to the Stockholders Agreement, among other things, Coffeyville Acquisition LLC had the right to exchange all shares of common stock in Coffeyville Refining & Marketing Holdings, Inc. held by Mr. Lipinski for such number of common units of Coffeyville Acquisition LLC or equity interests of a wholly-owned subsidiary of Coffeyville Acquisition LLC, in each case having a fair market value equal to the fair market value of the common stock in Coffeyville Refining & Marketing Holdings, Inc. held by Mr. Lipinski.

In October 2007, prior to our initial public offering, we entered into a subscription agreement with Mr. Lipinski pursuant to which Mr. Lipinski agreed to exchange his shares of common stock of Coffeyville Nitrogen Fertilizers, Inc. and Coffeyville Refining & Marketing Holdings, Inc. for shares of our common stock. In accordance with this agreement, we issued 247,471 shares of common stock to Mr. Lipinski. Prior to that stock issuance, Mr. Lipinski owned approximately 0.3128% of Coffeyville Refining and Marketing Holdings, Inc. and approximately 0.6401% of Coffeyville Nitrogen Fertilizer, Inc. These two companies owned all of the interests which became owned by CVR Energy upon the completion of its initial public offering. The allocation of value as of September 30, 2007 between Coffeyville Refining and Marketing Holdings, Inc. and Coffeyville Nitrogen Fertilizer, Inc. was 75.7717% and 24.2283%, respectively. The allocation of value was based on the two entities respective ownership interest in their subsidiaries taking into effect liabilities and receivables existing between the two companies. The number of shares issued to Mr. Lipinski was determined by grossing up the shares after our stock split by the weighted average percentage ownership of Mr. Lipinski in

the two entities and multiplying the result by Mr. Lipinski s weighted average percentage ownership. The table below illustrates the calculations of the shares issued to Mr. Lipinski.

	Relative ownership in all interests contributed to CVR Energy	
A	Coffeyville Refining and Marketing Holdings, Inc.	75.7717%
B	Coffeyville Nitrogen Fertilizer, Inc.	24.2283%
	Mr. Lipinski s Interests in the subsidiaries	
D	Coffeyville Refining and Marketing Holdings, Inc.	0.3128%
E	Coffeyville Nitrogen Fertilizer, Inc.	0.6401%
	Weighted average ownership in all assets	
F: = A x D	Coffeyville Refining and Marketing Holdings, Inc.	0.23701%
G: = B x E	Coffeyville Nitrogen Fertilizer, Inc.	0.15509%
H: = F + G	Mr. Lipinski s weighted average ownership interest	0.3921%
I	Original shares	100.00
J	Stock split	628,667.20
K: = I x J	Shares to members of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC	62,866,720.00
L: = H x (K/(1-H))	Mr. Lipinski s shares	247,471.00
M: = K + L	Total shares before director shares, our initial public offering and employee shares	63,114,191
N: = L/M	Mr. Lipinski s percentage of pre-offering shares	0.3921%

As a record holder of CVR Energy common stock on October 16, 2007, Mr. Lipinski received a dividend of $41,562 as part of a $10.6 million dividend approved by CVR Energy s board of directors in October 2007.

All decisions concerning Mr. Lipinski s compensation were approved by the compensation committee of Coffeyville Acquisition LLC without Mr. Lipinski s participation.

Registration Rights Agreement

In October 2007, we entered into a registration rights agreement with John J. Lipinski. Under the registration rights agreement, Mr. Lipinski will have the ability to exercise certain piggyback registration rights with respect to his own securities if any of our equity securities are offered to the public pursuant to a registration statement. The registration rights agreement also includes provisions dealing with holdback agreements, indemnification and contribution, and allocation of expenses. All of the shares in our company held directly by John J. Lipinski are entitled to these registration rights.

Wesley Clark Consulting Agreement

In connection with his retirement from our board of directors, we entered into a consulting agreement with General Wesley Clark whereby Mr. Clark will provide consulting and advisory services to us for a two year period in exchange for a monthly retainer of $2,000. As a member of the board of directors, Mr. Clark had been granted 244,038 Phantom Performance Points and 244,038 Phantom Services Points (together, the Points) under the Coffeyville Resources, LLC Phantom Unit Plan. Upon his leaving the board, Mr. Clark forfeited these Points. As additional compensation for his services as a consultant, Mr. Clark will receive a payment equal to the amounts that would have been distributed to Mr. Clark in respect of 65% of his Points had he continued to hold them during the period beginning on the annual meeting date and ending on the earlier of (i) December 1, 2010 or (ii) the date of the consummation of an Exit Event (as defined in the Coffeyville Acquisition LLC Limited Liability Company

Agreement) (but no earlier than January 15, 2009) (the Payment Date). In addition, Mr. Clark will receive the amount that would have been distributed in respect of 65% of his Points on the Payment Date assuming that (i) Mr. Clark remained on the board, (ii) all of the common stock of the Company then held by Coffeyville Acquisition LLC and Coffeyville Acquisition LLC II was sold at the closing price of common stock on the New York Stock Exchange on such Payment Date and (iii) the proceeds were distributed to the members of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC on such Payment Date pursuant to the LLC Agreements of each of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC.

Table of Contents

Transactions with Pegasus Partners II, L.P.

Pegasus Partners II, L.P., or Pegasus, was a majority owner of Coffeyville Group Holdings, LLC (Immediate Predecessor) during the period March 3, 2004 through June 24, 2005. On March 3, 2004, Coffeyville Group Holdings, LLC, through its wholly owned subsidiary, Coffeyville Resources, LLC, acquired the assets of the former Farmland petroleum division and one facility within Farmland s nitrogen fertilizer manufacturing and marketing division through a bankruptcy court auction process for approximately $107 million and the assumption of approximately $23 million of liabilities.

On March 3, 2004, Coffeyville Group Holdings, LLC entered into a management services agreement with Pegasus Capital Advisors, L.P., pursuant to which Pegasus Capital Advisors, L.P. provided Coffeyville Group Holdings, LLC with managerial and advisory services. In consideration for these services, Coffeyville Group Holdings, LLC agreed to pay Pegasus Capital Advisors, L.P. an annual fee of up to $1.0 million plus reimbursement for any out-of-pocket expenses. During the year ended December 31, 2004, Immediate Predecessor paid an aggregate of approximately $545,000 to Pegasus Capital Advisors, L.P. in fees under this agreement. $1,000,000 was expensed to selling, general, and administrative expenses for the 174 days ended June 23, 2005. In addition, Immediate Predecessor paid approximately $455,000 in legal fees on behalf of Pegasus Capital Advisors, L.P. in lieu of the remaining amount owed under the management fee. This management services agreement terminated at the time of the Subsequent Acquisition in June 2005.

Coffeyville Group Holdings, LLC paid Pegasus Capital Advisors, L.P. a $4.0 million transaction fee upon closing of the acquisition on March 3, 2004. The transaction fee related to a $2.5 million merger and acquisition fee and $1.5 million in deferred financing costs. In addition, in conjunction with the refinancing of our senior secured credit facility on May 10, 2004, Coffeyville Group Holdings, LLC paid an additional $1.25 million fee to Pegasus Capital Advisors, L.P. as a deferred financing cost.

On March 3, 2004, Coffeyville Group Holdings, LLC entered into Executive Purchase and Vesting Agreements with the then executive officers listed below providing for the sale by Immediate Predecessor to them of the number of our common units to the right of each executive officer s name at a purchase price of approximately $0.0056 per unit. Pursuant to the terms of these agreements, as amended, each executive officer s common units were to vest at a rate of 16.66% every six months with the first 16.66% vesting on November 10, 2004. In connection with their purchase of the common units pursuant to the Executive Purchase and Vesting Agreements, each of the executive officers at that time issued promissory notes in the amounts indicated below. These notes were paid in full on May 10, 2004.

Executive Officer	Number of Common Units	Amount of Promissory Note
Philip L. Rinaldi	3,717,647	$ 21,000
Abraham H. Kaplan	2,230,589	$ 12,600
George W. Dorsey	2,230,589	$ 12,600
Stanley A. Riemann	1,301,176	$ 7,350
James T. Rens	371,764	$ 2,100
Keith D. Osborn	650,588	$ 3,675
Kevan A. Vick	650,588	$ 3,675

On May 10, 2004, Mr. Rinaldi entered into another Executive Purchase and Vesting Agreement under the same terms as described above providing for the purchase of an additional 500,000 common units of Coffeyville Group Holdings, LLC for an aggregate purchase price of $2,850.

On May 10, 2004, Coffeyville Group Holdings, LLC refinanced its existing long-term debt with a $150 million term loan and used the proceeds of the borrowings to repay the outstanding borrowings under Coffeyville Group Holdings, LLC s previous credit facility. The borrowings were also used to distribute a $99,987,509 dividend, which included a preference payment of $63,200,000 plus a yield of $1,802,956 to the preferred unit holders and a $63,000 payment to the common unit holders for undistributed capital per the LLC agreement. The remaining $34,921,553 was distributed to the preferred and common unit holders pro rata according to their ownership percentages, as determined by the aggregate of the common and preferred units.

On October 8, 2004, Coffeyville Group Holdings, LLC entered into a joint venture with The Leiber Group, Inc., a company whose majority stockholder was Pegasus Partners II, L.P., the principal stockholder of Immediate Predecessor. In connection with the joint venture, Coffeyville Group Holdings, LLC contributed approximately 68.7% of its membership interests in Coffeyville Resources, LLC to CL JV Holdings, LLC, a Delaware limited liability company, or CL JV Holdings, and The Leiber Group, Inc. contributed the Judith Leiber business to CL JV Holdings. At the time of the Subsequent Acquisition, in June 2005, the joint venture was effectively terminated.

On January 13, 2005, Immediate Predecessor s board of directors authorized the following bonus payments to the following then executive officers, at that time, in recognition of the importance of retaining their services:

Executive Officer	Bonus Amount	
Philip L. Rinaldi	$	1,000,000
Abraham H. Kaplan	$	600,000
George W. Dorsey	$	300,000
Stanley A. Riemann	$	700,000
James T. Rens	$	150,000
Keith D. Osborn	$	150,000
Kevan A. Vick	$	150,000
Edmund S. Gross	$	200,000

During 2004 and 2005, Immediate Predecessor shared office space with Pegasus in New York, New York for which we paid Pegasus $10,000 per month.

On June 23, 2005, immediately prior to the Subsequent Acquisition, Coffeyville Group Holdings, LLC used available cash balances to distribute a $52,211,493 dividend to its preferred and common unit holders pro rata according to their ownership percentages, as determined by the aggregate of the common and preferred units.

Other Transactions

We paid INTERCAT, Inc. $525,507 during 2006 for chemical additives. Mr. Regis B. Lippert, a director of our company, is the principal shareholder and chief executive officer of INTERCAT, Inc. Mr. John J. Lipinski, the chief executive officer and president of our company and a member of our board of directors, is a director and member of the compensation committee of INTERCAT, Inc.

Related Party Transaction Policy

Our board of directors has adopted a Related Party Transaction Policy, which is designed to monitor and ensure the proper review, approval, ratification and disclosure of related party transactions involving us. This policy applies to any transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) in which we were, are or will be a participant and the amount involved exceeds $100,000, and in which any related party had, has or will have a direct or indirect material interest. The audit committee of our board of directors must review, approve and ratify a related party transaction if such transaction is consistent with the Related Party Transaction Policy and is on terms, taken as a whole, which the audit committee believes are no less favorable to us than could be obtained in an arms-length transaction with an unrelated third party, unless the audit committee otherwise determines that the transaction is not in our best interests. Any related party transaction or modification of such transaction which our board of directors has approved or ratified by the affirmative vote of a majority of directors, who do not have a direct or indirect material interest in such transaction, does not need to be approved or ratified by our audit committee. In addition, related party transactions involving compensation will be approved by our compensation committee in lieu of our audit committee.

Table of Contents

Conflicts of Interests Policy for Transactions between the Partnership and Us

Our board of directors has also adopted a Conflicts of Interests Policy, which is designed to monitor and ensure the proper review, approval, ratification and disclosure of transactions between the Partnership and us. The policy applies to any transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) between us or any of our subsidiaries, on the one hand, and the Partnership, its managing general partner and any subsidiary of the Partnership, on the other hand. According to the policy, all such transactions must be fair and reasonable to us. If such transaction is expected to involve a value, over the life of such transaction, of less than $1 million, no special procedures will be required. If such transaction is expected to involve a value of more than $1 million but less than $5 million, it is deemed to be fair and reasonable to us if (i) such transaction is approved by the conflicts committee of our board of directors, (ii) the terms of such transaction are no less favorable to us than those generally being provided to or available from unrelated third parties or (iii) such transaction, taking into account the totality of any other such transaction being entered into at that time between the parties involved (including other transaction that may be particularly favorable or advantageous to us), is equitable to CVR Energy. If such transaction is expected to involve a value, over the life of such transaction, of $5 million or more, it is deemed to be fair and reasonable to us if it has been approved by the conflicts committee of our board of directors.

Table of Contents

THE NITROGEN FERTILIZER LIMITED PARTNERSHIP

Background

In June 2007, we created a new limited partnership, CVR Partners, LP, or the Partnership. In October 2007, prior to our initial public offering, we transferred our nitrogen fertilizer business to this Partnership. The Partnership initially had three partners: a managing general partner, CVR GP, LLC, which we owned; a special general partner, CVR Special GP, LLC, which we owned; and a limited partner, Coffeyville Resources, LLC. We sold the managing general partner for $10.6 million to Coffeyville Acquisition III LLC, a newly created entity owned by the Goldman Sachs Funds, the Kelso Funds, our executive officers, Mr. Wesley Clark, Magnetite Asset Investors III L.L.C. and other members of our senior management team.

In connection with the creation of the Partnership, CVR GP, LLC, as the managing general partner, Coffeyville Resources, LLC, as the limited partner, and CVR Special GP, LLC, as a general partner, entered into a limited partnership agreement which set forth the various rights and responsibilities of the partners in the Partnership. In addition, we entered into a number of intercompany agreements with the Partnership and the managing general partner which regulate certain business relations among us, the Partnership and the managing general partner.

Contribution, Conveyance and Assumption Agreement

In October 2007, the Partnership entered into a contribution, conveyance and assumption agreement, or the contribution agreement, with the Partnership s managing general partner, CVR Special GP, LLC (our subsidiary that holds a general partner interest in the Partnership), and Coffeyville Resources, LLC (our subsidiary that holds a limited partner interest in the Partnership). Pursuant to the contribution agreement, Coffeyville Resources, LLC transferred our subsidiary that owns the nitrogen fertilizer business to the Partnership in exchange for (1) the issuance to CVR Special GP, LLC of 30,303,000 special GP units, representing a 99.9% general partner interest in the Partnership, (2) the issuance to Coffeyville Resources, LLC of 30,333 special LP units, representing a 0.1% limited partner interest in the Partnership, (3) the issuance to the managing general partner of the managing general partner interest in the Partnership and (4) the agreement by the Partnership, contingent upon the Partnership consummating an initial public or private offering, to reimburse us for capital expenditures we incurred during the two year period prior to the sale of the managing general partner to Coffeyville Acquisition III LLC, in connection with the operations of the fertilizer plant (currently estimated to be $18.4 million). The Partnership assumed all liabilities arising out of or related to the ownership of the nitrogen fertilizer business to the extent arising or accruing on and after the date of transfer.

Sale of Managing General Partner to Coffeyville Acquisition III LLC

Following formation of the Partnership pursuant to the contribution agreement in October 2007, the following entities and individuals contributed the following amounts in cash to Coffeyville Acquisition III LLC, a newly formed entity owned by our controlling stockholders and executive officers.

Coffeyville Acquisition III LLC used these contributions to purchase the managing general partner of the Partnership from us:

Contributing Parties	**Amount Contributed**
The Goldman Sachs Funds	$ 5,227,584
The Kelso Funds	5,145,787
John J. Lipinski	68,146
Stanley A. Riemann	16,359
James T. Rens	10,225
Edmund S. Gross	1,227
Robert W. Haugen	4,090
Wyatt E. Jernigan	4,090
Kevan A. Vick	10,225
Christopher G. Swanberg	1,022
Daniel J. Daly, Jr.	2,045
Wesley Clark	10,225
Others	98,975
Total Contribution	$ 10,600,000

Coffeyville Acquisition III purchased the managing general partner from us for $10.6 million, which our board of directors determined, after consultation with management, represented the fair market value of the managing general partner of the Partnership at that time. The valuation of the managing general partner interest was based on a discounted cash flow analysis, using a discount rate commensurate with the risk profile of the managing general partner interest. The key assumptions underlying the analysis were commodity price projections, which were used to estimate the Partnership s raw material costs and output revenues. Other business expenses of the Partnership were estimated based on management s projections. The Partnership s cash distributions were assumed to be flat at expected forward fertilizer prices, with cash reserves developed in periods of high prices and cash reserves reduced in periods of lower prices. The Partnership s projected cash distributions to the managing general partner under the terms of the Partnership s partnership agreement used for the valuation were modeled based on the structure of the Partnership, the managing general partner s incentive distribution rights (IDRs) and management s expectations of the Partnership s operations, including production volumes and operating costs, which were developed by management based on historical experience. As commodity price curve projections were key assumptions in the discounted cash flow analysis, alternative price curve projections were considered in order to test the reasonableness of these assumptions, which gave management an added level of assurance as to such reasonableness. Price projections were based on information received from Blue Johnson and Associates, a fertilizer industry consultant in the United States which we routinely use for fertilizer market analysis. There can be no assurance that the value of the managing general partner will not differ in the future from the amount initially paid for it.

February 2008 Filing of Form S-1 by CVR Partners, LP

On February 28, 2008, the Partnership filed a Form S-1 registration statement (the Partnership S-1) with the SEC for an initial public offering (the Partnership Offering) of common units representing limited partner interests in the Partnership. On June 13, 2008, the Company announced that the managing general partner of the Partnership had decided that it would postpone indefinitely the Partnership s initial public offering. The Partnership may elect to move forward with a public or private offering in the future.

Description of Partnership Interests Initially Following Formation

The partnership agreement provides that initially the Partnership has three types of partnership interests: (1) special GP units, representing special general partner interests, which are owned by the special general partner, (2) special LP units, representing a limited partner interest, which are owned by Coffeyville Resources, LLC, and (3) a managing general partner interest which has associated IDRs which are held by the managing general partner.

Special Units. The special units include special GP units and special LP units. We indirectly own all 30,303,000 special GP units and all 30,333 special LP units. The special GP units are special general partner interests giving the holder thereof specified joint management rights (which we refer to as special GP rights), including rights with respect to the appointment, termination and compensation of the chief executive officer and the chief financial officer of the managing general partner, and entitling the holder to participate in Partnership distributions and allocations of income and loss. Special LP units have identical voting and distribution rights as the special GP units, but represent limited partner interests in the Partnership and do not give the holder thereof the special GP rights.

In accordance with the partnership agreement, the special units are entitled to payment of a set target distribution of $0.4313 per unit ($13.1 million in the aggregate for all our special units each quarter), or $1.7252 per unit on an annualized basis ($52.3 million in the aggregate for all our special units annually), prior to the payment of any quarterly distribution in respect of the IDRs. For more information on cash distributions to the special units and the IDRs please see Cash Distributions by the Partnership . We are permitted to sell the special units at any time without the consent of the managing general partner, subject to compliance with applicable securities laws, but upon any sale of special GP units to an unrelated third party the special GP rights will no longer apply to such units.

Managing General Partner Interest. The managing general partner interest, which is held solely by the managing general partner, entitles the holder to manage (subject to our special GP rights) the business and operations of the Partnership, but does not entitle the holder to participate in Partnership distributions or allocations except in respect of associated IDRs. IDRs represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the target distribution ($0.4313 per unit per quarter) has been paid and following distribution of the aggregate adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009 to the special units and/or the common and subordinated units (if issued). In addition, there can be no distributions paid on the managing general partner s IDRs for so long as the Partnership or its subsidiaries are guarantors under our Credit Facility. The IDRs are not transferable apart from the general partner interest. The managing general partner can be sold without the consent of other partners in the Partnership.

Provisions Regarding an Initial Offering by the Partnership

Under the partnership agreement, the managing general partner has the sole discretion to cause the Partnership to undertake an initial private or public offering, subject to our joint management rights (as holder of the special GP rights, described below) if the offering involves the issuance of more than $200 million of the Partnership s interests (exclusive of the underwriters option, if any). There is no assurance that the Partnership will undertake or consummate a public or private offering.

Under the contribution agreement, if Fertilizer GP elects to cause the Partnership to undertake an initial private or public offering (in either case, the Partnership s initial offering), Fertilizer GP must give prompt notice to us of such election and the proposed terms of the offering. We have agreed to use our commercially reasonable efforts to take such actions as Fertilizer GP reasonably requests in order to effectuate and permit the consummation of the offering. We have agreed that Fertilizer GP may structure the initial offering to include (1) a secondary offering of interests by us or (2) a primary offering of interests by the Partnership, possibly together with an incurrence of indebtedness by the Partnership, where a use of proceeds is to redeem units from us (with a per-unit redemption price equal to the price at which each unit is purchased from the Partnership, net of sales commissions or underwriting discounts) (a special GP offering), provided that in either case the number of units associated with the special GP offering is reasonably expected by Fertilizer GP to generate no more than $100 million in net proceeds to us (exclusive of the underwriters option, if any). The special GP offering may not be consummated without our consent if the net proceeds to us are less than $10 per unit. If the initial public offering includes a special GP offering, unless we otherwise agree with the

Partnership, the special GP offering will be increased to cover our pro rata portion of any exercise of the underwriters option, if any.

Under the contribution agreement, if Fertilizer GP reasonably determines that, in order to consummate the initial offering, it is necessary or appropriate for the Partnership and its subsidiaries to be released from their obligations under our Credit Facility and our swap arrangements with J. Aron, then Fertilizer GP must give prompt written notice to us describing the requested amendments. The notice must be given 90 days prior to the anticipated closing date of the initial offering. We will be required to use our commercially reasonable efforts to effect the releases or amendments. We will not be considered to have made commercially reasonable efforts if we do not effect such requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us. In order to effect the requested modifications, we may require that (1) the initial offering include a special GP offering generating at least $140 million in net proceeds to us and (2) the Partnership raise an amount of cash (from the issuance of equity or incurrence of indebtedness) equal to $75.0 million minus the amount of capital expenditures for which it will reimburse us from the proceeds of its initial public or private offering and distribute that cash to us prior to, or concurrently with, the closing of its initial public or private offering.

If the Partnership consummates an initial public or private offering and we sell units, or our units are redeemed, in a special GP offering, or the Partnership makes a distribution to us of proceeds of the offering or debt financing, such sale, redemption or distribution would likely result in taxable gain to us and such taxable gain could be significant. If the Partnership consummates an initial public or private offering, regardless of whether we sell units, the distributions that we receive from the Partnership could decrease because the Partnership s distributions will be shared with the new limited partners. Additionally, when the Partnership issues units or engages in certain other transactions, the Partnership will determine the fair market value of its assets and allocate any unrealized gain or loss attributable to those assets to the capital accounts of the existing partners. As a result of this revaluation and the Partnership s adoption of the remedial allocation method under Section 704(c) of the Internal Revenue Code (i) new unitholders will be allocated deductions as if the tax basis of the Partnership s property were equal to the fair market value thereof at the time of the offering, and (ii) we will be allocated reverse Section 704(c) allocations of income or loss over time consistent with our allocation of unrealized gain or loss.

If the Partnership consummates an initial offering as either a primary or secondary offering, our special units, other than those sold or redeemed in a special GP offering, if any, will be converted into a combination of (1) common units and (2) subordinated units. The special units will be converted into common units and subordinated units, on a one-for-one basis, such that the lesser of (1) 40% of all outstanding units after the initial offering (prior to the exercise of the underwriters option, if any) and (2) all of the units owned by us, will be subordinated. For a description of the common units and subordinated units please see Description of Partnership Interests Following Initial Offering . The special GP units will convert into common GP units or subordinated GP units and the special LP units will convert into common LP units or subordinated LP units.

The following table sets forth the number of special GP units and special LP units that are currently outstanding and illustrates the number of common GP units, subordinated GP units, common LP units and subordinated LP units we will own, as well as the number of common LP units that public unitholders will own, assuming the Partnership s initial offering involves a total of 10 million common LP units, 7 million of which are our special units (converted into common LP units immediately prior to sale directly in the initial offering, or redeemed using the proceeds from the issuance of common LP units by the Partnership) and 3 million of which are new common LP units. The following table assumes that the 7 million of our special units sold or redeemed reduce our special LP units and special GP units pro rata (i.e., 99.9% from our special GP units and 0.1% from our special LP units).

Table of Contents

This information is presented for illustrative purposes only. There can be no assurance the Partnership will undertake an initial offering consistent with these assumptions or at all.

	Initial	Following Partnership Initial Offering	
	Special Units	Common Units	Subordinated Units
Owned by us	30,303,000 special GP units 30,333 special LP units	9,990,000 common GP units 10,000 common LP units	13,320,000 subordinated GP units 13,333 subordinated LP units
Owned by public		10,000,000 common LP units	

The partnership agreement prohibits Fertilizer GP from causing the Partnership to undertake or consummate an initial offering unless the board of directors of Fertilizer GP determines, after consultation with us, that the Partnership will likely be able to earn and pay the minimum quarterly distribution (which is currently set at $0.375 per unit) on all units for each of the two consecutive, nonoverlapping four-quarter periods following the initial offering. As an illustration, the Partnership would need to earn and pay $50 million during each of the two consecutive, nonoverlapping four-quarter periods based upon the number of units (i.e., 33,333,333 total units) in the hypothetical illustrated in the table above. If Fertilizer GP determines that the Partnership is not likely to be able to earn and pay the minimum quarterly distribution for such periods, Fertilizer GP may, in its sole discretion and effective upon closing of the initial offering, reduce the minimum quarterly distribution to an amount it determines to be appropriate and likely to be earned and paid during such periods.

The contribution agreement also provides that if the initial offering is not consummated by October 24, 2009, Fertilizer GP can require us to purchase the managing general partner interest. This put right expires on the earlier of (1) October 24, 2012 and (2) the closing of the Partnership s initial offering. If the Partnership s initial offering is not consummated by October 24, 2012, we have the right to require Fertilizer GP to sell the managing general partner interest to us. This call right expires on the closing of the Partnership s initial offering. In the event of an exercise of a put right or a call right, the purchase price will be the fair market value of the managing general partner interest at the time of purchase. The fair market value will be determined by an independent investment banking firm selected by us and Fertilizer GP. The independent investment banking firm may consider the value of the Partnership s assets, the rights and obligations of Fertilizer GP and other factors it may deem relevant but the fair market value shall not include any control premium. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest in the Nitrogen Fertilizer Business If the Partnership does not consummate an initial offering by October 24, 2009, Fertilizer GP can require us to purchase its managing general partner interest in the Partnership. We may not have requisite funds to do so .

Description of Partnership Interests Following Initial Offering

Common Units. The common units, if issued, will be comprised of common GP units and common LP units. The common GP units will be special general partner interests giving the holder special GP rights (described above), including rights with respect to the appointment, termination and compensation of the chief executive officer and the chief financial officer of the managing general partner, and entitling the holder to participate in Partnership distributions and allocations on a pro rata basis with common LP units. Common LP units will have identical voting and distribution rights as the common GP units, but will represent limited partner interests in the Partnership and will not give the holder thereof special GP rights. The common units will be entitled to payment of the minimum quarterly distribution prior to the payment of any quarterly distribution on the subordinated units or the IDRs. For more information of the rights and preferences of holders of the common units, subordinated units and IDRs in the Partnership s distributions, please see Cash Distributions by the Partnership.

We will be permitted to sell the common units we own at any time without the consent of the managing general partner, subject to compliance with applicable securities laws. The common GP units will automatically convert to common LP units immediately prior to sale thereof to an unrelated third party. The common GP units will automatically convert into common LP units (with no special GP rights) immediately if the holder of the common GP units, together with all of its affiliates, ceases to own 15% or more of all units of the Partnership (not including the managing general partner interest).

Subordinated Units. The subordinated units, if issued, will be comprised of subordinated GP units and subordinated LP units. The subordinated GP units will be special general partner interests giving the holder special GP rights. Subordinated LP units will have identical voting and distribution rights as the subordinated GP units, but will represent limited partner interests in the Partnership and will not give the holder thereof special GP rights. The subordinated units will entitle the holder to participate in Partnership distributions and allocations on a subordinated basis to the common units (as described in Cash Distributions by the Partnership). During the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the set minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. As a result, if the Partnership consummates an initial offering, the portion of our special units that are converted into subordinated units will be subordinated to the common units and may not receive distributions unless and until the common units have received the minimum quarterly distribution, plus any accrued and unpaid arrearages in the minimum quarterly distribution from prior quarters. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest In the Nitrogen Fertilizer Business Our rights to receive distributions from the Partnership may be limited over time and Risk Factors Risks Related to the Limited Partnership Structure Through Which We Hold Our Interest In the Nitrogen Fertilizer Business If the Partnership completes a public offering or private placement of limited partner interests, our voting power in the Partnership would be reduced and our rights to distributions from the Partnership could be materially adversely affected.

We will be permitted to sell the subordinated units we own at any time without the consent of the managing general partner, subject to compliance with applicable securities laws. The subordinated units will automatically convert into common units on the second day after the distribution of cash in respect of the last quarter in the subordination period (which will end no earlier than five years after the initial offering), although up to 50% may convert earlier. The subordinated GP units will automatically convert to subordinated LP units immediately prior to sale thereof to an unrelated third party. The subordinated GP units will automatically convert into subordinated LP units immediately if the holder of the subordinated GP units, together with all of its affiliates, ceases to own 15% or more of all units of the Partnership.

Managing General Partner Interest. The managing general partner interest will continue to be outstanding following the initial offering.

Management of the Partnership

The managing general partner manages the Partnership s operations and activities, subject to our joint management rights, as specified in the partnership agreement. Among other things, the managing general partner has sole authority to effect an initial public or private offering of the Partnership, including the right to determine the timing, size (subject to our consent rights for any initial offering in excess of $200 million, exclusive of the underwriters option, if any) and underwriters or initial purchasers, if any, for any initial offering. The Partnership s managing general partner is wholly-owned by an entity controlled by the Goldman Sachs Funds, the Kelso Funds and certain members of our senior management team. The operations of the managing general partner, in its capacity as the managing general partner of the Partnership, are managed by its board of directors. As of the date of this prospectus, the board of directors of the managing general partner consisted of Donna R. Ecton, John J. Lipinski, Scott L. Lebovitz, George E. Matelich, Frank M. Muller, Jr., Stanley

Table of Contents

de J. Osborne and Kenneth A. Pontarelli. Actions by the managing general partner that are made in its individual capacity will be made by the sole member of the managing general partner and not by its board of directors. The managing general partner is not elected by the unitholders or us and is not subject to re-election on a regular basis in the future. The officers of the managing general partner manage the day-to-day affairs of the Partnership s business.

The special general partner, which we own, has special management rights. The special management rights will terminate if we cease to own 15% of more of all units of the Partnership. Our management rights include:

- appointment rights and consent rights for the termination of employment and compensation of the chief executive officer and chief financial officer of the managing general partner, not to be exercised unreasonably (our approval for appointment of an officer is deemed given if the officer is an executive officer of CVR Energy);

- the right to appoint two directors to the board of directors of the managing general partner and one such director to any committee thereof (subject to certain exceptions);

- consent rights over any merger by the Partnership into another entity where:

  - for so long as we own 50% or more of all units of the Partnership immediately prior to the merger, less than 60% of the equity interests of the resulting entity are owned by the pre-merger unitholders of the Partnership;

  - for so long as we own 25% or more of all units of the Partnership immediately prior to the merger, less than 50% of the equity interests of the resulting entity are owned by the pre-merger unitholders of the Partnership; and

  - for so long as we own more than 15% of all of the units of the Partnership immediately prior to the merger, less than 40% of the equity interests of the resulting entity are owned by the pre-merger unitholders of the Partnership;

- consent rights over any purchase or sale, exchange or other transfer of assets or entities with a purchase/sale price equal to 50% or more of the Partnership s asset value; and

- consent rights over any incurrence of indebtedness or issuance of Partnership interests with rights to distribution or in liquidation ranking prior or senior to the common units, in either case in excess of $125 million ($200 million in the case of the Partnership s initial public or private offering, exclusive of the underwriters option, if any), increased by 80% of the purchase price for assets or entities whose purchase was approved by us as described in the immediately preceding bullet point.

As of the date of this prospectus, the board of directors of the managing general partner consists of seven directors, including two representatives of the Goldman Sachs Funds, two representatives of the Kelso Funds, Donna R. Ecton and Frank M. Muller, Jr., who are independent directors and John J. Lipinksi, chief executive officer and president of the managing general partner and CVR Energy. If the Partnership effects an initial public offering in the future, the board of directors of the managing general partner will be required, subject to phase-in requirements of any national securities exchange upon which the Partnership s common units are listed for trading, to have at least three members who are not officers or employees, and are otherwise independent, of the entity which owns the managing general partner, and its affiliates, including CVR Energy and the Partnership s general partners. In addition, if an initial public offering of the Partnership occurs, the board of directors of the managing general partner will be required to maintain an audit committee comprised of at least three independent directors.

The partnership agreement permits the board of directors of the managing general partner to establish a conflicts committee, comprised of at least one independent director, that may determine if the resolution of a conflict of interest with the Partnership s general partners or their affiliates is fair and reasonable to the Partnership. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all of the Partnership s partners and not a breach by the general partners of any duties they may owe the Partnership or the unitholders of the Partnership.

Cash Distributions by the Partnership

Available Cash. The partnership agreement requires the Partnership to make quarterly distributions of 100% of its available cash. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter

less the amount of cash reserves established by the managing general partner to:

provide for the proper conduct of the Partnership s business (including the satisfaction of obligations in respect of pre-paid fertilizer contracts, future capital expenditures, anticipated future credit needs and the payment of expenses and fees, including payments to the managing general partner);

comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which the Partnership or any of its subsidiaries is a party or by which the Partnership is bound or its assets are subject; and

provide funds for distributions in respect of any one or more of the next eight quarters, provided, however, that following an initial public offering of the Partnership, the managing general partner may not establish cash reserves pursuant to this clause if the effect of such reserves would be that the Partnership would be unable to distribute the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon with respect to any such quarter;

plus all 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 generally borrowings that are used solely for working capital purposes or to make distributions to partners.

Cash distributions will be made within 45 days after the end of each quarter. The amount of distributions paid by the Partnership and the decision to make any distribution will be determined by the managing general partner, taking into consideration the terms of the partnership agreement.

Prior to the earlier to occur of (i) such time as the limitations described below in Non-IDR surplus amount no longer apply, after which time available cash from operating surplus could be distributed in respect of the IDRs, assuming each unit has received at least the first target distribution, as described below, and (ii) an initial offering by the Partnership, after which there will be limited partners to whom available cash could be distributed, all available cash is distributed to us, as holder of the special units. Because all available cash is currently distributed to us, the board of directors of Fertilizer GP has not adopted a formal distribution policy.

Operating Surplus and Capital Surplus. All cash distributed by the Partnership will be characterized either as operating surplus or capital surplus. The Partnership will distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. Operating surplus for any period generally consists of:

$60 million (as described below); plus

all of the Partnership s cash receipts after formation (reset to the date of the Partnership s initial offering if an initial offering occurs), excluding cash from interim capital transactions (as described below); plus working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; plus

cash distributions paid on equity interests issued by the Partnership to finance all or any portion of the construction, expansion or improvement of the Partnership s facilities during the period from such financing until the earlier to occur of the date the capital asset is put into service or the date it is abandoned or disposed of; plus cash distributions paid on equity interests issued by the Partnership to pay the construction period interest on debt incurred, or to pay construction period distributions on equity issued, to finance the construction, expansion and improvement projects referred to above; less

all of the Partnership s operating expenditures (as defined below) after formation (reset to the date of closing of the Partnership s initial offering if an initial offering occurs); less

the amount of cash reserves established by the managing general partner to provide funds for future operating expenditures (which does not include expansion capital expenditures).

If a working capital borrowing, which increases operating surplus, 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 not be treated as a reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to unitholders. For example, it includes a provision that will enable the Partnership, if it chooses, to distribute as operating surplus up to $60 million of cash 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 would be to increase operating surplus by the amount of any such cash distributions.

Operating expenditures generally means all of the Partnership s expenditures, including its expenses, taxes, reimbursements or payments of expenses to its managing general partner, repayment of working capital borrowings, debt service payments and capital expenditures, provided that operating expenditures will not include:

repayments of working capital borrowings, if such working capital borrowings were outstanding for twelve months, not repaid, but deemed repaid, thus decreasing operating surplus at such time;

payments (including prepayments) 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 ; or

distributions to partners.

Where capital expenditures are made in part for expansion and in part for other purposes, the managing general partner shall determine the allocation between the amounts paid for each.

Interim capital transactions means the following transactions if they occur prior to liquidation of the Partnership: (a) borrowings, refinancings or refundings of indebtedness (other than working capital borrowings and other than for items purchased on open account or for a deferred purchase price in the ordinary course of business); (b) sales of equity interests and debt securities; and (c) sales or other voluntary or involuntary dispositions of any assets other than (i) sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business, and

(ii) sales or other dispositions of assets as part of normal retirements or replacements of assets.

Maintenance capital expenditures reduce operating surplus, but expansion capital expenditures and investment capital expenditures do not. Maintenance capital expenditures represent capital expenditures to replace partially or fully depreciated assets to maintain the Partnership s operating capacity (or productivity) or capital base. Maintenance capital expenditures include expenditures required to maintain equipment reliability, plant integrity and safety and to address environmental laws and regulations. Maintenance capital expenditures also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of the construction,

Table of Contents

improvement or development of a replacement asset that is paid during the period that begins when the Partnership enters into a binding commitment or commences constructing or developing a replacement asset and ending on the earlier to occur of the date any such replacement asset commences commercial service or the date it is abandoned or disposed of.

Expansion capital expenditures include expenditures to acquire or construct assets to grow the Partnership s business and to expand fertilizer production capacity. Expansion capital expenditures also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of the construction of such a capital improvement during the period that commences when the Partnership enters into a binding obligation to commence construction of a capital improvement and ending on the date such capital improvement commences commercial service or the date that it is abandoned or disposed of.

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely 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 the Partnership s existing operating capacity or productivity, but which are not expected to expand for the long-term the Partnership s operating capacity or asset base.

As described above, none of the Partnership s investment capital expenditures or expansion capital expenditures are subtracted from operating surplus. Because investment capital expenditures and expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued to finance all of the portion of the construction, replacement or improvement of a capital asset during the period that begins when the Partnership enters into a binding obligation to commence construction of a capital improvement and ending on the earlier to occur of the date any such capital asset commences commercial service or the date that it is abandoned or disposed of, such interest payments and equity distributions are also not subtracted from operating surplus.

The officers and directors of the managing general partner determine how to allocate a capital expenditure for the acquisition or expansion of the Partnership s assets between maintenance capital expenditures and expansion capital expenditures.

Definition of Capital Surplus. Capital surplus is generally generated only by:

- borrowings other than working capital borrowings;
- sales of debt securities and equity interests; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of the normal retirement or replacement of assets.

Distributions from Operating Surplus.

The Partnership s distribution structure with respect to operating surplus will change based upon the occurrence of three events: (1) distribution by the Partnership of the non-IDR surplus amount (as defined below), together with a release of the guarantees by the Partnership and its subsidiaries of our Credit Facility, (2) occurrence of an initial offering by the Partnership (following which all or a portion of our interest will be converted into subordinated units and the minimum quarterly distribution could be reduced) and (3) expiration (or early termination) of the subordination period.

Minimum Quarterly Distributions. The minimum quarterly distribution, or MQD, represents the set quarterly distribution amount that the common units, if issued, will be entitled to prior to the payment of any quarterly distribution on the subordinated units. The amount of the MQD is set in Partnership s partnership agreement at $0.375 per unit, or $1.50 per unit on an annualized basis. The partnership agreement prohibits the managing general partner from causing the Partnership to undertake or consummate an initial offering unless the board of directors of the managing general partner, after consultation with us, concludes that the Partnership will be likely to be able to earn and pay the MQD on all units for each of the two consecutive, nonoverlapping four-quarter periods following the initial offering. If the managing general partner determines that the Partnership is not likely to be able to earn and pay the MQD for such periods, the managing general partner may, in its sole discretion and effective upon closing of the initial offering, reduce the MQD to an amount it determines to be appropriate and likely to be earned and paid during such periods. If the Partnership were to distribute $0.375 per unit on the number of units we own, we would receive a quarterly distribution of $11.4 million in the aggregate. The MQD for any period of less than a full calendar quarter (e.g., the periods before and after the closing of an initial offering by the Partnership) will be adjusted based on the actual length of the periods. To the extent we receive such amounts from the Partnership in the form of quarterly distributions, we will generally not be able to distribute such amounts to our stockholders due to restrictions contained in our Credit Facility. See Dividend Policy.

Target Distributions. The Partnership s partnership agreement provides for target distribution levels. After the limitations described below in Non-IDR surplus amount no longer apply, the managing general partner s IDRs will entitle it to receive increasing percentages of any incremental quarterly cash distributed by the Partnership as the target distribution levels for each quarter are exceeded. There are three target distribution levels set in the partnership agreement: $0.4313, $0.4688 and $0.5625, representing 115%, 125% and 150%, respectively, of the initial MQD amount. The target distribution levels for any period of less than a full calendar quarter (e.g., the periods before and after the closing of an initial offering by the Partnership) will be adjusted based on the actual length of the periods. The target distribution levels will not be adjusted in connection with any reduction of the MQD in connection with the Partnership s initial offering unless we otherwise agree with the managing general partner.

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and the Partnership s managing general partner up to and above the various target distribution levels. The amounts set forth under marginal percentage interest in distributions are the percentage interests of the Partnership s managing general partner and the unitholders in any available cash from operating surplus the Partnership distributes up to and including the corresponding amount in the column Total Quarterly Distribution Target Amount, until the available cash from operating surplus the Partnership distributes reaches the next target distribution level, if any. The percentage interests shown for the unitholders and managing 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 the managing general partner represent distributions in respect of the IDRs.

Marginal Percentage Interest in Distributions

	Total Quarterly Distribution Target Amount	Special Units	Managing General Partner
Minimum Quarterly Distribution	$0.375	100%	0%
First Target Distribution	Up to $0.4313	100%	0%
Second Target Distribution	Above $0.4313 and up to $0.4688	87%	13%
Third Target Distribution	Above $0.4688 and up to $0.5625	77%	23%
Thereafter	Above $0.5625	52%	48%

233

Table of Contents

If legislation is enacted or if existing law is modified or interpreted by a court of competent jurisdiction so that the Partnership or any of its subsidiaries becomes taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, the managing 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 the managing general partner s estimate of the Partnership s aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation) and the denominator of which is the sum of available cash for that quarter plus the managing general partner s estimate of the Partnership s aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Non-IDR Surplus Amount. There will be no distributions paid on the IDRs until the aggregate adjusted operating surplus (as described below) generated by the Partnership during the period from October 24, 2007 through December 31, 2009, or the non-IDR surplus amount, has been distributed in respect of the special units, or, following an initial public offering of the Partnership, the common and subordinated units (if any are issued). In addition, there will be no distributions paid on the IDRs for so long as the Partnership or its subsidiaries are guarantors under our Credit Facility.

Definition of Adjusted Operating Surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes the $60 million basket included as a component of operating surplus, net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus for any period generally means:

- operating surplus generated with respect to that period (which does not include the $60 million basket described in the first bullet point of the definition of operating surplus above); less

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

- any net reduction 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 to the extent required by any debt instrument for the repayment of principal, interest or premium.

If the Partnership consummates an initial offering, cash received by the Partnership or its subsidiaries in respect of accounts receivable existing as of the closing of such an offering will be deemed to not be operating surplus and thus will be disregarded when calculating adjusted operating surplus.

Distributions Prior to the Partnership s Initial Offering (if any). Prior to the Partnership s initial offering (if any), quarterly distributions of available cash from operating surplus (as described below) will be paid solely in respect of the special units until the non-IDR surplus amount has been distributed. After the limitations described in Non-IDR surplus amount no longer apply and prior to the Partnership s initial offering (if any), quarterly distributions of available cash from operating surplus will be paid in the following manner: (1) *First*, to the special units, until each special unit has received a total quarterly distribution equal to $0.4313 (the first target distribution), (2) *Second,* (i) 13% to the managing general partner interest (in respect of the IDRs) and (ii) 87% to the special units until each special unit has received a total quarterly amount equal to $0.4688 (the second target distribution), (3) *Third*, (i) 23% to the managing general partner interest (in respect of the IDRs) and (ii) 77% to the special units, until each special unit has received a total quarterly amount equal to $0.5625 (the third target distribution), and (4) *Thereafter*, (i) 48% to the managing general partner interest (in respect of the IDRs) and (ii) 52% to the special units.

Distributions from Capital Surplus. Capital surplus is generally generated only by borrowings other than working capital borrowings, sales of debt securities and equity interests, and sales or other dispositions of assets for cash, other than inventory, accounts receivable and the other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

The Partnership will make distributions of available cash from capital surplus, if any, in the following manner: (1) *First*, to all unitholders, pro rata, until the minimum quarterly distribution is reduced to zero, as described below, (2) *Second*, to the common unitholders, if any, pro rata, until the Partnership distributes 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 (3) *Thereafter*, the Partnership will make all distributions of available cash from capital surplus as if they were from operating surplus. The preceding discussion is based on the assumptions that the Partnership does not issue additional classes of equity interests.

The partnership agreement will treat a distribution of capital surplus as the repayment of the consideration for the issuance of a unit by the Partnership, 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, after any of these distributions are made, it may be easier for the managing 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.

Once the Partnership reduces the minimum quarterly distribution and the target distribution levels to zero, the Partnership will then make all future distributions from operating surplus, with 52% being paid to the unitholders, pro rata, and 48% to the Partnership s managing general partner.

Distributions of Cash Upon Liquidation. If the Partnership dissolves in accordance with the partnership agreement, the Partnership will sell or otherwise dispose of its assets in a process called liquidation. The Partnership will first apply the proceeds of liquidation to the payment of its creditors. The Partnership will distribute any remaining proceeds to the unitholders and the managing general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of the Partnership s 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 the unitholder to the Partnership for its units, which we refer to as the initial unit price for each unit. With respect to our special units, the initial unit price will be the value of the nitrogen fertilizer business we contribute to the Partnership, divided by the number of special units we receive. The initial unit price for the common units issued by the Partnership in the initial offering, if any, will be the price paid for the common units. If there are common units and subordinated units outstanding, the allocation is intended, to the extent possible, to entitle the holders of common units to a preference over the holders of subordinated units upon the Partnership s 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 the Partnership s liquidation to enable the holders of units, including us, to fully recover all of the initial unit price. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of the managing general partner.

The manner of the adjustment for gain is set forth in the partnership agreement. If the Partnership s liquidation occurs after the Partnership s initial offering, if any, and before the end of the subordination period, the Partnership will allocate any gain to the partners in the following manner: (1) *First*, to the managing 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, (2) *Second*, to the common unitholders, pro rata, 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 the liquidation occurs, and (iii) any unpaid arrearages in payment of the minimum quarterly distribution, (3) *Third*, to the subordinated unitholders, pro rata, 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 the liquidation occurs, (4) *Fourth*, to all unitholders, pro rata, until the Partnership allocates 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 the Partnership s 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 the Partnership distributed to the unitholders, pro rata, for each quarter of the Partnership s existence, (5) *Fifth*, 87% to all unitholders, pro rata, and 13% to the managing general partner, until the Partnership allocates 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 the Partnership s existence; less the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that the Partnership distributed 87% to the unitholders, pro rata, and 13% to the managing general partner for each quarter of the Partnership s existence, (6) *Sixth*, 77% to all unitholders, pro rata, and 23% to the managing general partner, until the Partnership allocates 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 the Partnership s 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 the Partnership distributed 77% to the unitholders, pro rata, and 23% to the managing general partner for each quarter of the Partnership s existence, and (7) *Thereafter*, 52% to all unitholders, pro rata, and 48% to the managing general partner. The percentages set forth above are based on the assumption that the Partnership has not issued additional classes of equity interests.

If the liquidation occurs before the Partnership s initial offering, the special units will receive allocations of gain in the same manner as described above for the common units, except that the distinction between common units and subordinated units will not be relevant, so that subclause (iii) of clause (2) above and all of clause (3) above will not be applicable. If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that subclause (iii) of clause (2) above and all of the third bullet point above will no longer be applicable.

If the Partnership s liquidation occurs after the Partnership s initial offering, if any, and before the end of the subordination period, the Partnership will generally allocate any loss to the managing general partner and the unitholders in the following manner: (1) *First*, to holders of subordinated units in proportion to the positive balances in their capital accounts, until the capital accounts of the subordinated unitholders have been reduced to zero, (2) *Second*, to the holders of common units in proportion to the positive balances in their capital accounts, until the capital accounts of the common unitholders have been reduced to zero, and (3) *Thereafter,* 100% to the managing general partner.

If the liquidation occurs before the Partnership s initial offering, the special units will receive allocations of loss in the same manner as described above for the common units, except that the distinction between common units and subordinated units will not be relevant, so that all of clause (1) above will not be applicable. If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of clause (1) will no longer be applicable.

Adjustments to Capital Accounts. The Partnership will make adjustments to capital accounts upon the issuance of additional units. In doing so, the Partnership will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the managing general partner in the same manner as the Partnership allocates gain or loss upon liquidation. In the event that the Partnership makes positive adjustments to the capital accounts upon the issuance of additional units, the Partnership will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon the Partnership s liquidation in a manner which results, to the extent possible, in the managing 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.

Withdrawal or Removal of the Managing General Partner

Except as described below, the managing general partner has agreed not to withdraw voluntarily as the Partnership s managing general partner prior to June 30, 2017 without obtaining the approval of the holders of at least a majority of the outstanding units, excluding units held by the managing general partner and its affiliates (including us), and furnishing an opinion of counsel regarding limited liability and tax matters. On or after June 30, 2017, the managing general partner may withdraw as managing general partner without first obtaining approval of any unitholder by giving 90 days written notice, and that withdrawal will not constitute a violation of the partnership agreement. Notwithstanding the information above, the managing general partner may withdraw without unitholder approval upon 90 days notice to the unitholders if at least 50% of the outstanding units are held or controlled by one person and its affiliates other than the managing general partner and its affiliates. In addition, the partnership agreement permits the managing general partner in some instances to sell or otherwise transfer all of its managing general partner interest without the approval of the unitholders. See Transfer of Managing General Partner Interest.

Upon withdrawal of the managing general partner under any circumstances, other than as a result of a transfer by the managing general partner of all or a part of its general partner interest in the Partnership, the holders of a majority of the outstanding classes of units voting as a single class may select a successor to that withdrawing managing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, the Partnership will be dissolved, wound up and liquidated, unless within a specified period of time after that withdrawal, the holders of a unit majority agree in writing to continue the business of the Partnership and to appoint a successor managing general partner. See Termination and Dissolution.

The managing general partner may not be removed unless that removal is approved by the vote of the holders of not less than 80% of the outstanding units, voting together as a single class, including units held by the managing general partner and its affiliates, and the Partnership receives an opinion of counsel regarding limited liability and tax matters. Prior to October 26, 2012, the managing general partner can only be removed for cause. Any removal of the managing general partner is also subject to the approval of a successor managing general partner by the vote of the unitholders holding a majority of each class of outstanding units, voting as separate classes.

The partnership agreement also provides that if the managing general partner is removed as managing general partner under circumstances where cause does not exist and no units held by us, including our subsidiary that holds the subordinated units (if any) and our other affiliates, are voted in favor of that removal, the subordination period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis, and any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished.

If the managing general partner is removed as managing general partner under circumstances where cause does not exist and no units held by the managing general partner and its affiliates (which will include us until such time as we cease to be an affiliate of the managing general partner) are voted in favor of that removal, the managing general partner will have the right to convert its managing general partner interest, including the incentive distribution rights, into common units or to receive cash in exchange for those interests based on the fair market value of the interests at the time.

In the event of removal of the managing general partner under circumstances where cause exists or withdrawal of the managing general partner where that withdrawal violates the partnership agreement, a successor managing general partner will have the option to purchase the managing general partner interest, including the IDRs, of the departing managing general partner for a cash payment equal to the fair market value of the managing general partner interest.

Under all other circumstances where the managing general partner withdraws or is removed, the departing managing

Table of Contents

general partner will have the option to require the successor managing general partner to purchase the managing general partner interest of the departing managing general partner for its fair market value. In each case, this fair market value will be determined by agreement between the departing managing general partner and the successor managing general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing managing general partner and the successor managing general partner will determine the fair market value. If the departing managing general partner and the successor managing general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing managing general partner or the successor managing general partner, the departing managing general partner s general partner interest, including its IDRs, will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, the Partnership will be required to reimburse the departing managing general partner for all amounts due to it, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing managing general partner or its affiliates for the Partnership s benefit.

Voting Rights

The partnership agreement provides that various matters require the approval of a unit majority. A unit majority requires (1) prior to the initial offering, the approval of a majority of the special units; (2) during the subordination period, the approval of a majority of the common units, excluding those common units held by the managing general partner and its affiliates (which will include us until such time as we cease to be an affiliate of the managing general partner), and a majority of the subordinated units, voting as separate classes; and (3) after the subordination period, the approval of a majority of the common units. In voting their units, the Partnership s general partners and their affiliates will have no fiduciary duty or obligation whatsoever to the Partnership or the other partners, including any duty to act in good faith or in the best interests of the Partnership and its other partners.

The following is a summary of the vote requirements specified for certain matters under the partnership agreement:

Issuance of Additional Units: no approval right.

Amendment of the Partnership Agreement: certain amendments may be made by the managing general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority.

Merger of the Partnership or the Sale of all or Substantially all of the Partnership s Assets: unit majority in certain circumstances. In addition, the holder of special GP rights has joint management rights with respect to some mergers.

Dissolution of the Partnership: unit majority.

Continuation of the Partnership upon Dissolution: unit majority.

Withdrawal of the Managing General Partner: under most circumstances, a unit majority is required for the withdrawal of the managing general partner prior to June 30, 2017 in a manner which would cause a dissolution of the Partnership.

Removal of the Managing General Partner: not less than 80% of the outstanding units, voting as a single class, including units held by the managing general partner and its affiliates (i) for cause prior to October 26, 2012 or (ii) with or without cause (as defined in the partnership agreement) on or after October 26, 2012.

Transfer of the Managing General Partner s General Partner Interest: the managing general partner may transfer all, but not less than all, of its managing general partner interest

Table of Contents

in the Partnership without a vote of any unitholders and without our approval, to an affiliate or to another person (other than an individual) in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets to, such person. The approval of a majority of the outstanding units, excluding units held by the managing general partner and its affiliates, voting as a class, and our approval, is required in other circumstances for a transfer of the managing general partner interest to a third party prior to October 26, 2017.

Transfer of Ownership Interests in the Managing General Partner: no approval required at any time.

Issuance of Additional Partnership Interests

The partnership agreement authorizes the Partnership to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by the managing general partner without the approval of the unitholders, subject to the special GP rights with respect to the issuance of equity with rights to distribution or in liquidation ranking prior to or senior to the common units.

Upon issuance of additional partnership interests, the Partnership s managing general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership interests whenever, and on the same terms that, the Partnership issues those interests to persons other than the managing general partner and its affiliates, to the extent necessary to maintain its and its affiliates percentage interest, including such interest represented by common units and subordinated units, that existed immediately prior to each issuance. We will have similar rights to purchase common units, subordinated units or other partnership interests from the Partnership, except that our rights will not apply to any issuance of interests by the Partnership in its initial offering. For the purpose of these rights, we and the managing general partner shall be deemed not to be affiliates of one another, unless we otherwise agree. Other holders of units will not have preemptive rights to acquire additional common units or other partnership interests unless they are granted those rights in connection with the issuance of their units by the Partnership.

Amendment of the Partnership Agreement

General. Amendments to the partnership agreement may be proposed only by the managing general partner. However, the managing general partner has no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to the Partnership or any partner, including any duty to act in good faith or in the best interests of the Partnership or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, the managing general partner is