CVR ENERGY INC
Form 10-K
March 28, 2008

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 001-33492

CVR Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**61-1512186**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
2277 Plaza Drive, Suite 500 **Sugar Land, Texas**	**77479**
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant s Telephone Number, including Area Code:
(281) 207-3200

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered

Common Stock, $.01 par value per share	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No þ

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The Registrant consummated the initial public offering of its common stock on October 26, 2007. Accordingly, there was no public market for the Registrant s common stock as of June 30, 2007, the last day of the Registrant s most recently completed second fiscal quarter. As of March 27, 2008, the aggregate market value of the voting and non-voting common equity held by non-affiliates was $532,983,396.

Indicate the number of shares outstanding of each of the Registrant s classes of common stock, as of the latest practicable date.

Class	Outstanding at March 27, 2008
Common Stock, par value $0.01 per share	86,141,291 shares

Documents Incorporated By Reference

Document	Parts Incorporated

Proxy Statement for the 2008 Annual Meeting of Stockholders	Items 10, 11, 12, 13 and 14 of Part III

TABLE OF CONTENTS

PART I

Item 1. *Business*

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 incentive distribution rights (the IDRs)) in a limited partnership which produces the nitrogen fertilizers ammonia and urea ammonia nitrate (UAN).

Our petroleum business includes a 113,500 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 southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, and (3) 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 refined products distribution systems.

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). A majority of the ammonia produced by the nitrogen fertilizer plant is further upgraded to UAN fertilizer (a solution of urea and ammonium nitrate in 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.

We have 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, and operating income of $270.8 million, $281.6 million and $204.3 million, 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 $162.5 million of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

The limited partnership which operates the nitrogen fertilizer business filed a registration statement with the Securities and Exchange Commission (the SEC) on February 28, 2008 in connection with selling certain of its interests to the public but there is no assurance that such offering will be consummated on the terms described in the registration statement or at all.

Our History

Our refinery assets, which began operation in 1906, and the nitrogen fertilizer plant, which was built in 2000, were operated as a small component of Farmland Industries, Inc., an agricultural cooperative, and its predecessors 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. Coffeyville Group Holdings, LLC operated our business from March 3, 2004 through June 24, 2005.

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 by certain funds affiliated with Goldman, Sachs & Co. and Kelso &

Company, L.P. (the Goldman Sachs Funds and the Kelso Funds, respectively), acquired all of the subsidiaries of Coffeyville Group Holdings, LLC. Coffeyville Acquisition operated our business from June 24, 2005 until CVR Energy s initial public offering in October 2007.

CVR Energy was formed in September 2006 as a subsidiary of Coffeyville Acquisition in order to consummate an initial public offering of the businesses operated by Coffeyville Acquisition. Prior to CVR

Energy s initial public offering in October 2007, (1) Coffeyville Acquisition transferred all of its businesses to CVR Energy in exchange for all of CVR Energy s common stock, (2) Coffeyville Acquisition was effectively split into two entities, with the Kelso Funds controlling Coffeyville Acquisition and the Goldman Sachs Funds controlling Coffeyville Acquisition II LLC and CVR Energy s senior management receiving an equivalent position in each of the two entities, (3) we transferred our nitrogen fertilizer business into a newly formed limited partnership in exchange for all of the partnership interests in the limited partnership and (4) we sold all of the interests of the managing general partner of this partnership to an entity owned by our controlling stockholders and senior management at fair market value on the date of the transfer. CVR Energy consummated its initial public offering on October 26, 2007.

On February 28, 2008, the Partnership filed a registration statement with the SEC to effect a contemplated initial public offering of its common units representing limited partner interests. The registration statement provides that upon consummation of the Partnership s initial public offering, we will indirectly own the Partnership s special general partner and approximately 87% of the outstanding units of the Partnership. There can be no assurance that any such offering will be consummated on the terms described in the registration statement or at all.

Petroleum Business

Asset Description

We operate a complex cracking and coking medium-sour oil refinery which at maximum capacity has the ability to produce 123,500 bpd of petroleum products. This amount represents approximately 17% of our region s output. The facility is situated on approximately 440 acres in southeast Kansas, approximately 100 miles from Cushing, Oklahoma, a major crude oil trading and storage hub.

The Coffeyville 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. For the year ended December 31, 2007, our refinery s product yield included gasoline (mainly regular unleaded) (43%), diesel fuel (mainly ultra low sulfur diesel) (40%), and coke and other refined products such as NGC (propane, butane), slurry, reformer feeds, sulfur, gas oil and produced fuel (17%).

Our petroleum business also includes the following auxiliary operating assets:

Crude Oil Gathering System. We own and operate a 25,000 bpd 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, 41 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 terminaling facilities for asphalt and refined fuels in Phillipsburg, Kansas. The asphalt storage and terminaling facilities are used to receive, store and redeliver asphalt for another oil company for a fee pursuant to an asphalt services agreement.

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 2 million barrels located outside our refinery.

Table of Contents

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 now 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 28-35 degrees and 1.0-1.2% 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.

We obtain all of the crude oil for our refinery under a credit intermediation agreement with J. Aron (other than crude oil that we acquire in Kansas, Missouri, Nebraska, Oklahoma and all states adjacent thereto). The credit intermediation agreement helps us reduce our inventory position and mitigate crude pricing risk.

Marketing and Distribution

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 Coffeyville refinery has a maximum delivery capability of 40,000 bpd of finished gasoline and diesel fuels.

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. We sell bulk products based on industry market related indexes such as Platt s or NYMEX related Group Market (Midwest) prices. We have also implemented a rack marketing initiative. Truck rack sales are at daily posted prices which are influenced by the NYMEX, competitor pricing and group spot market differentials.

Competition

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 and distillate), refinery efficiency, refinery product mix and product distribution and transportation costs.

In addition to seven mid-continent refineries operated by Conoco Phillips, Frontier Oil, Valero, NCRA, Gary Williams Energy, Sinclair and Sunoco, our oil refinery in Coffeyville, Kansas competes against 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.

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.

Nitrogen Fertilizer Business

The nitrogen fertilizer business operates the only nitrogen fertilizer plant in North America that utilizes a pet 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 approximately $85 million fertilizer plant expansion, of which approximately $8 million was incurred as of December 31, 2007. We estimate this expansion will increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium priced UAN by approximately 50%. We currently expect to complete this expansion in late 2009 or early 2010.

The facility uses a gasification process licensed from an affiliate of the General Electric Company (General Electric) to convert pet coke to high purity hydrogen for subsequent conversion to ammonia. It uses between 950 to 1,050 tons per day of pet coke from our refinery and another 250 to 300 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 nitrogen fertilizer plant has the following advantages compared to competing natural gas-based facilities:

Significantly Lower Cost Position. The nitrogen fertilizer plant s pet coke gasification process uses less than 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. Because the nitrogen fertilizer plant uses pet coke, the nitrogen fertilizer business has a significant cost advantage over other North American natural gas-based fertilizer producers. Our adjacent refinery has supplied on average more than 75% of the nitrogen fertilizer business pet coke needs during the last four years.

Table of Contents

Strategic Location with Transportation Advantage. The nitrogen fertilizer business believes that selling products to customers within economic rail transportation limits of the nitrogen fertilizer plant and reducing transportation costs are keys to maintaining its profitability. Due to the nitrogen fertilizer 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 our nitrogen fertilizer 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 storage, barge or pipeline freight charges. Consequently, because these costs are not incurred, the nitrogen fertilizer business estimates that it enjoys a distribution cost advantage over U.S. Gulf Coast ammonia and UAN producers and importers, assuming in each case freight rates and pipeline tariffs for U.S. Gulf Coast producers and importers as recently in effect.

On-Stream Factor. The on-stream factor is a measure of how long the units comprising the nitrogen fertilizer facility have been operational over a given period. The nitrogen fertilizer business expects 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**
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 in 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% 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 business 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 needs 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 available to the nitrogen fertilizer plant.

Pet coke is produced as a by-product of the refinery s coker unit process, which is one step in refining crude oil into gasoline, diesel and jet fuel. In order to refine heavy crude oils, which are lower in cost and more prevalent than higher quality crude, refiners use coker units, which help to convert the heavier components of these crudes. 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 business 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 Gulf Coast coke market, due mainly to more stable transportation costs. Pet coke transportation costs have gone up substantially in both the Atlantic and Pacific sectors. Given the fact that the majority of the nitrogen fertilizer business coke suppliers are located in the Midwest, the nitrogen fertilizer business s geographic location gives it a significant freight cost advantage over its Gulf Coast coke 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 $26.83. The U.S. Gulf Coast market annual average price during the same

Table of Contents

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 refinery expansions should help to further supply the Midwest coke market.

The Linde Group (Linde) 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 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 the nitrogen fertilizer business requirements for liquid or gaseous oxygen, liquid or gaseous nitrogen or clean dry air exceed specified instantaneous flow rates by at least 10%, the nitrogen fertilizer business can solicit bids from Linde and third parties to supply its incremental product needs. The nitrogen fertilizer business is required to provide notice to Linde of the approximate quantity of excess product that it will need and the approximate date by which it will need it; the nitrogen fertilizer business 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.

The nitrogen fertilizer business imports start-up steam for the nitrogen fertilizer plant from our oil refinery, and then exports steam back to the oil refinery once all units in the nitrogen fertilizer plant are in service. 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 to high purity hydrogen for subsequent conversion to ammonia. The nitrogen fertilizer plant is capable of processing approximately 1,300 tons per day of pet coke from our 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 the Linde air separation unit. Partial oxidation reactions take place and the synthesis gas (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 CO_2. 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 unit. The syngas is then fed to a pressure swing absorption (PSA) where the remaining impurities are extracted. The PSA unit reduces residual carbon monoxide and CO_2 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 air separation unit in the ammonia unit to form the ammonia product. A large 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 nitrogen fertilizer business fertilizer products are Kansas, Missouri, Nebraska, Iowa, Illinois, Colorado and Texas. The nitrogen fertilizer business markets the ammonia products to industrial and agricultural customers and the UAN products 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 in November. The highest level of ammonia demand is traditionally in the spring pre-plant period, from March through May. There are also small fill volumes that move in the off-season to fill available storage at the dealer level.

Ammonia and UAN are distributed by truck or by railcar. If delivered by truck, products are sold on an FOB basis, and freight is normally arranged by the customer. The nitrogen fertilizer business leases a fleet of railcars for use in product delivery. The nitrogen fertilizer business 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 our nitrogen fertilizer facility. The nitrogen fertilizer business 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 near the Union Pacific Railroad lines or destinations that 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 the nitrogen fertilizer business 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 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. The nitrogen fertilizer business 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, the top five ammonia customers in the aggregate represented 55.2%, 51.9% and 62.1% of the nitrogen fertilizer business ammonia sales, respectively, and the top five UAN customers in the aggregate represented 43.1%, 30.0% and 38.7% of the nitrogen fertilizer business 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 the nitrogen fertilizer business UAN sales, respectively. During the year ended December 31, 2006, Brandt Consolidated Inc. and MFA accounted for 22.2% and 13.1% of its 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.

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 business maintains a large fleet of leased 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 business main competitors 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 represented 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 business and operations and the nitrogen fertilizer business by imposing:

- restrictions on operations and/or the need to install enhanced or additional controls;
- the need to obtain and comply with permits 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 marketed by our petroleum business and the nitrogen fertilizer business, primarily gasoline, diesel fuel, UAN and ammonia.

The petroleum refining industry is subject to frequent public and governmental scrutiny of its environmental compliance. As a result, 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) and the federal Clean Air Act have not yet been finalized, are under governmental or judicial review or are being revised. These regulations and other new air and water quality standards and stricter fuel regulations could result in increased capital, operating and compliance costs.

The principal environmental risks associated with our petroleum operations and the nitrogen fertilizer business 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 the federal Clean Air Act s 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 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 Benzene Waste Operations National Emission Standard for Hazardous Air Pollutants (NESHAP), New Source Performance Standards, New Source Review, and Leak Detection and Repair. 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 impose 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 expect to begin 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 performed 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. No penalties are expected to be imposed as a result of the Consent Decree.

Over the course of the last several years, the EPA embarked on a 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 a global settlement, we believe our incremental capital exposure would be limited primarily to the retrofit and replacement of heaters and boilers over a five to seven year timeframe.

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 the Occupational Safety and Health Administration (OSHA) following the August 2007 ammonia release OSHA issued citations against both the nitrogen fertilizer facility and the refinery seeking penalties totaling $163,000.

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). We believe that our production of ULSG and ULSD will make us eligible for significant tax benefits in 2007 and 2008.

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 would defer meeting final low sulfur Tier II gasoline standards until January 1, 2011 in exchange for our meeting low sulfur highway diesel requirements by January 1, 2007. We completed the construction and startup phase of our Ultra Low Sulfur Diesel Hydrodesulfurization unit in late 2006 and met the conditions of the hardship waiver. We are currently continuing our phased construction and startup of projects related to meeting our compliance date with ULSG standards. 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 $69 million between 2008 and 2010.

As a result of the 2007 flood, our refinery was not able to meet the annual average sulfur standard required in our hardship waiver. We provided timely notice to the EPA that we would not be able to meet the waiver requirement for 2007. Ordinarily, a refiner would purchase sulfur credits to meet the standard requirement. However, our hardship waiver does not allow sulfur credits to be used in 2006 and 2007. We have been working with the EPA to resolve the matter. In anticipation of settlement, the refinery purchased $3.6 million worth of sulfur credits that would equate to our exceeding the standard imposed by the hardship waiver. We will either use the credits by applying them towards our gasoline pool account, or we will permanently retire the credits as part of our settlement. Because of the extraordinary nature of the 2007 flood, we do not anticipate the imposition of fines or penalties to resolve this matter. Additionally, we expect to meet our 2008 annual average sulfur limits as the exceedance for 2007 was outside of our control.

Table of Contents

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.

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 focused on initiatives to reduce greenhouse gas emissions, particularly CO_2, and is working with a company with expertise in CO_2 capture and storage systems 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 is expected, if completed, 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.

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 Coffeyville 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.

The anticipated remediation costs through 2011 were estimated, as of December 31, 2007, 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 Coffeyville 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.

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 Coffeyville 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.

Financial Assurance. We were required in the Consent Decree to establish $15 million in financial assurance to cover the projected cleanup costs posed by the Coffeyville and Phillipsburg facilities in the event we failed to fulfill our clean-up obligations. In accordance with the Consent Decree, this financial assurance is currently provided by a bond posted by Original Predecessor, Farmland. We will be required to replace the financial assurance currently provided by Farmland and have so replaced approximately $4.5 million to date. 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 million.

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 and Health Matters

We operate a comprehensive safety, health and security program, involving active participation of employees at all levels of the organization. We measure our success in the safety and health 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. For the year ended December 31, 2006, we had a recordable injury rate of 0.30 in our petroleum business and 4.90 in the nitrogen fertilizer business. 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. Our recordable injury rate for all business units was 0.28 for the period from January 2007 to December 2007. 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, and 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, there can be no assurances 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 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 from the areas around 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 facilities from unauthorized entry and exit from the facilities 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 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 December 31, 2007, 428 employees were employed in our petroleum business, 105 were employed by the nitrogen fertilizer business and 44 employees were employed at our offices in Sugar Land, Texas and Kansas City, Kansas.

We entered into collective bargaining agreements which as of December 31, 2007 cover approximately 41% 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 Partnership s nitrogen fertilizer business. The services we provide under the agreement include the following services, among others:

services by our employees in capacities equivalent to the capacities of 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;

administrative and professional services, including legal, accounting services, human resources, insurance, tax, credit, finance, government affairs and regulatory affairs;

managing 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 interests, 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.

Flood and Crude Oil Discharge

Overview

During the weekend of June 30, 2007, torrential rains in southeast 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 flooded and forced to conduct emergency shutdowns and evacuate. 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 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 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.

The total third party cost to repair the refinery is currently estimated at approximately $85 million. In addition, we spent approximately $3.5 million to repair the nitrogen fertilizer facility in the year ended December 31, 2007, and we anticipate that all further flood-related repairs for the nitrogen fertilizer business will cost approximately $0.7 million. We will pay for all flood-related repairs for the nitrogen fertilizer facility, whether or not the Partnership s contemplated initial public offering is consummated. 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, (b) oil was observed in the Verdigris River and in flood waters that had inundated a portion of the city of Coffeyville, and (c) a sheen of oil was observed in the Verdigris River extending downstream from our refinery approximately ten miles.

Representatives from the KDHE and the Oklahoma Department of Environmental Quality have also been heavily involved in participating 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

Table of Contents

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 ninety (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, 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 are currently remediating the contamination caused by the crude oil discharge and expect our remedial actions to continue until May 2008. Total net costs recorded as of December 31, 2007 associated with remediation and third party property damage incurred by the crude oil discharge are approximately $23.5 million. This amount is net of anticipated insurance recoveries of $21.4 million. As of December 31, 2007, we have recovered $10.0 million from our insurance carriers under our environmental policies. 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 class action 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 December 31, 2007, 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. We are presently reviewing and adjusting these claims.

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 is 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 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 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 excess of $5 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. 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, it is unlikely that any of the lost profits incurred because of the flood can be claimed under insurance.

Financial Impact on 2007 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. 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 accounts receivable from insurers for flood related matters approximated $85.3 million at December 31, 2007, for which we believe collection is probable, including $11.4 million related to the crude oil discharge and $73.9 million as a result of the flood damage to our facilities.

As of December 31, 2007, we had received insurance proceeds of $10.0 million under our property insurance policy and an additional $10.0 million under our environmental policies related to recovery of certain costs associated with the crude oil discharge. 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 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.

Trademarks, Trade Names and Service Marks

This Annual Report on Form 10-K for the year ended December 31, 2007 (the Report) includes trademarks, including the registered trademark of COFFEYVILLE RESOURCES®, CVR Energy™ for which we have applied for federal registration, and other trademarks. This Report also contains trademarks, service marks, copyrights and trade names of other companies.

Table of Contents

Executive Officers

The following table sets forth the names, positions and ages (as of December 31, 2007) of each person who is an executive officer of CVR Energy. We also indicate in the biographies below which executive officers of CVR Energy hold similar positions with the managing general partner of the Partnership. Senior management of CVR Energy manages the Partnership pursuant to a services agreement among us, the Partnership and the Partnership s managing general partner.

Name	Age	Position
John J. Lipinski	56	Chairman of the Board of Directors, Chief Executive Officer and President
Stanley A. Riemann	56	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	49	Executive Vice President, Refining Operations
Wyatt E. Jernigan	56	Executive Vice President, Crude Oil Acquisition and Petroleum Marketing
Kevan A. Vick	53	Executive Vice President and Fertilizer General Manager
Christopher G. Swanberg	49	Vice President, Environmental, Health and Safety

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 of directors since September 2006, chief executive officer and president of Coffeyville Acquisition since June 2005 and chief executive officer and president of Coffeyville Acquisition II and Coffeyville Acquisition III 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. On May 31, 2002, Farmland filed for Chapter 11 bankruptcy protection. 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

Table of Contents

Association. He currently serves on the Board of The Fertilizer Institute. Mr. Riemann received a bachelor of science from the University of Nebraska and an MBA 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 18 years in various accounting and financial positions associated with the fertilizer and energy industry. Mr. Rens received a Bachelor of Science 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 Bachelor of Arts degree in history from Tulane University, a Juris Doctor from the University of Kansas and an MBA from the University of Kansas.

Daniel J. Daly, Jr. has been our Executive Vice President, Strategy since December 2007 and our Senior Vice President, Accounting and Controls, since June 2005. 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, LLC since June 24, 2005. Since October 2007 Mr. Haugen has also served as executive vice president, refining operations at Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. 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 mid-stream/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, LLC since June 24, 2005. Since October 2007 Mr. Jernigan has also served as executive vice

Table of Contents

president, crude oil acquisition and petroleum marketing at Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC. 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, LLC 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 one of the most highly respected executives 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 LLC, he was general manager of nitrogen manufacturing at Farmland from January 2001 to February 2004. Mr. Vick received a bachelor of science 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 MBA from the University of Tulsa.

Item 1A. Risk Factors

You should carefully consider each of the following risks together with the other information contained in this Report and all of the information set forth in our filings with the SEC. 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.

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.

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.

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

Our refinery requires approximately 89,000 bpd of crude oil in addition to the light sweet crude oil we gather locally in Kansas and northern Oklahoma. We obtain a significant amount 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. 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

Table of Contents

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. 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.

Our profitability is 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 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. Crude oil prices may not remain at current levels and the light/heavy or sweet/sour spread may decline, which could result in a decline in profitability or operating losses.

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 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 EPA and KDHE to address certain allegations of Clean Air Act violations by Farmland at the Coffeyville oil refinery in order to reduce environmental risks and 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 all 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 have a material adverse effect on our ability to meet the requirements imposed by the Consent Decree.

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. 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 $69 million between 2008 and 2010. Changes in these laws or interpretations thereof could result in 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.

We may have additional capital needs for which our internally generated cash flows and other sources of liquidity may not be adequate.

If we cannot generate cash flow or otherwise secure sufficient liquidity to support our short-term and long-term capital requirements, we may be unable to comply with certain environmental standards or pursue our business strategies, in which case our operations may not perform as well as we currently expect. We have substantial short-term and long-term capital needs, including 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. Our short-term working capital needs are primarily crude oil purchase requirements, which fluctuate with the pricing and sourcing of crude oil. We also have significant long-term needs for cash, including deferred payments owed under derivative contracts we have entered into with J. Aron and debt repayment obligations. 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 $47 million per year over the next five years.

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.

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 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.

Table of Contents

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.

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, it would have less cash available for future distributions and other purposes, including the funding of its ongoing expenses, its indebtedness levels would increase and its ongoing debt service requirements would increase. This could negatively impact the nitrogen fertilizer business financial condition, results of operations, ability to pursue its business strategy and ability to make future quarterly 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 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 nitrogen fertilizer products 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 nitrogen fertilizer business is cyclical and volatile, which exposes 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. In the past, periods of high demand, high capacity utilization, and increasing operating margins have tended, in light of the low technological barriers to entry to the nitrogen fertilizer production market, to result in new plant investment and increased production until supply exceeds demand, followed by periods of declining prices and declining capacity utilization until the cycle is repeated. 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 business, cash flow and the ability of the nitrogen fertilizer business to make quarterly 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. Fertilizers 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. Competitors utilizing different corporate structures may be better able to withstand lower cash flows than the Partnership can as a limited partnership. 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 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.

In addition, the nitrogen fertilizer business relies on the air separation plant owned by Linde to provide oxygen, nitrogen and compressed dry air to the nitrogen fertilizer plant s gasifier. This air separation plant has experienced numerous momentary interruptions, thereby causing interruptions in the gasifier operations. The operations of the nitrogen fertilizer business require a reliable supply of raw materials. A disruption of its supply could prevent it from producing its products at current levels and its reputation, customer relationships, results of operations and cash flow could be materially harmed.

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.

Table of Contents

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. 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.

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 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 negative impact 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 finished products. In addition, new regulations could be implemented affecting the equipment used to ship its finished 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 or regulations, or new interpretations of existing laws or regulations, 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 the nitrogen fertilizer business 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 the nitrogen fertilizer business 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 nitrogen fertilizers, 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 location of the nitrogen fertilizer business plant provides a transportation cost advantage over many of its competitors. However, there is no assurance that competitors transportation costs will not decline, reducing the nitrogen fertilizer business price advantage.

The nitrogen fertilizer plant is located within the U.S. farm belt, where the majority of the end users of nitrogen fertilizer products in the United States grow their crops. Accordingly, the nitrogen fertilizer business currently has a transportation cost advantage over many of its competitors, who produce fertilizer outside of this region and incur greater costs in transporting their products over longer distances 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.

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 Partnership s 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 business 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 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

Table of Contents

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 business nitrogen fertilizer plant, or individual units within the plant, will require scheduled or unscheduled downtime for maintenance or repairs. In general, the facility requires scheduled turnaround maintenance every two years and the next scheduled turnaround is currently expected to occur in the third quarter of 2008. Scheduled and unscheduled maintenance could reduce net income and cash flow during the period of time that any of our units are not operating.

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

We have incurred and will continue to incur 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 the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required extensive repairs. As of December 31, 2007, we had incurred approximately $79.2 million and $3.5 million in third party costs to repair the refinery and fertilizer facilities, respectively. In addition, we currently estimate that approximately $6.0 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 complete a rapid shutdown of the refinery immediately before the flooding, 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 are currently remediating the contamination caused by the crude oil discharge. As of December 31, 2007, we have recorded total gross costs associated with the repair of, and other matters relating to, damage to our facilities and with third party and property damage remediation of approximately $146.8 million. Anticipated insurance recoveries of approximately $105.3 million have been recorded as of December 31, 2007, resulting in a net cost of approximately $41.5 million. The Company has not estimated any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from class action 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 SEC. Such excess costs and damages could be material.

Table of Contents

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.

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 orders 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 the ability of the nitrogen fertilizer business to make cash distributions.

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 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 RCRA corrective action orders related to contamination at or that originated from the Coffeyville refinery (which includes portions of the nitrogen fertilizer plant) and the Phillipsburg terminal. If significant unforeseen 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 or expect to incur 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 as an air pollutant.

Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of discussion or implementation. These include proposed federal legislation and state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in greenhouse gas emissions. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any greenhouse gas emissions program. These actions could also impact the consumption of refined products, thereby affecting our refinery 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.

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 the ability of the nitrogen fertilizer business to make cash distributions.

We are subject to the requirements of 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 growth in the profitability of the refined products industry which 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. Furthermore, our historical financial statements do not reflect the new limited partnership structure prior to October 24, 2007 and therefore our past financial performance may not be an accurate indicator of future performance.

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 will initially 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 the Partnership consummates 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. On February 28, 2008, the Partnership filed a registration statement with the SEC in order to offer and sell its partnership interests to the public, but there can be no assurance that any offering by the Partnership will be consummated. 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 the Partnership s proposed initial public offering and therefore our past financial performance may not be an accurate indicator of future performance.

Our commodity derivative activities could result in losses and may result 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. The Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 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. Because this derivative is based on NYMEX prices while our revenue is based on prices in the Coffeyville supply area, the contracts cannot completely eliminate all 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.

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 and $(103.2) million for the years ended December 31, 2006 and 2007, respectively. As of December 31, 2007, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $42.3 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.

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% and 36.8% of our petroleum sales for the years ended December 31, 2006 and 2007, respectively. Further, in the aggregate the top five ammonia customers of the nitrogen fertilizer business represented 51.9% and 62.1% of its ammonia sales for the years ended December 31, 2006 and 2007, respectively, and the top five UAN customers of the nitrogen fertilizer business represented 30.0% and 38.7% 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 case 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 third 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.

In addition, in connection with any potential acquisition or expansion project involving the nitrogen fertilizer business, the nitrogen fertilizer business will need to consider whether the business it intends to acquire or expansion project it intends to pursue (including the CO_2 sequestration or sale project the nitrogen fertilizer business is considering) could affect the nitrogen fertilizer business tax treatment as a partnership for federal income tax purposes. If the nitrogen fertilizer business is otherwise unable to conclude that the activities of the business being acquired or the expansion project would not affect our treatment as a partnership for federal income tax purposes, the nitrogen fertilizer business may elect to seek a ruling from the Internal Revenue Service (IRS). Seeking such a ruling could be costly or, in the case of competitive acquisitions, place the nitrogen fertilizer business in a competitive disadvantage compared to other potential acquirers who do not seek such a ruling. If the nitrogen fertilizer business is unable to conclude that an activity would not affect its treatment as a partnership for federal income tax purposes, the nitrogen fertilizer business may choose to acquire such business or develop such expansion project in a corporate subsidiary, which would subject the income related to such activity to entity-level taxation.

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 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.

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

Table of Contents

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 available 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 December 31, 2007, we had total debt outstanding of $500.8 million, $39.4 million in funded letters of credit outstanding and borrowing availability of $110.6 million under our credit facility. 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:

- 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 credit facility 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 December 31, 2007, would correspondingly change our interest expense by approximately $5.0 million for the year ended December 31, 2007.

In addition to our debt service obligations, our operations require substantial investments on a continuing basis. Our ability to make scheduled debt payments, 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. 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 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.

In connection with the Partnership s initial public offering, 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.

In connection with the Partnership s initial public offering (or if the initial public offering is not consummated but subsequently the managing general partner elects to pursue a public or private offering), we will be required to obtain amendments to our credit facility, as well as 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. 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 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 December 31, 2007, approximately 41% 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.

Table of Contents

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.

As a public company, 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 controls 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.

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 controls systems to allow management to report on, and our independent auditors to audit, our internal controls 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 United States generally accepted accounting principles (U.S. GAAP) our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. As a public company, 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 controls 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 controls in a timely manner, our independent registered public accounting firm may not be able to certify as to the effectiveness of our internal controls over financial reporting pursuant to an audit of our internal controls 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 controls 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.

Table of Contents

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, you may 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.

Table of Contents

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.

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 after our initial public offering 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.

The Goldman Sachs Funds and the Kelso Funds 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.

The Goldman Sachs Funds and the Kelso Funds each beneficially own 36.5% of our outstanding common stock. As a result, 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 outstanding 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. 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.

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 agreement, the Goldman Sachs Funds and the Kelso Funds will 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 and the Kelso Funds, as well as our senior management, rather than our company and our stockholders. Such increase in value could be significant if the Partnership performs well.

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 our phantom unit appreciation 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 grant 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. If either the Goldman Sachs Funds or the Kelso Funds sell any or all 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 appreciation plans. This could negatively affect our cash reserves, which could negatively affect our results of operations and financial condition. 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 $24.94 per share, which was the closing price of our common stock on December 31, 2007.

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. 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.

Shares eligible for future sale 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 March 27, 2008. Of these shares, the 23,000,000 shares of common stock sold in the initial public offering are 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. Our principal stockholders, directors and executive officers have entered into lock-up agreements, pursuant to which they agreed, subject to certain exceptions, not to sell or transfer, directly or indirectly, any shares of our common stock for a period of 180 days until April 19, 2008, subject to extension in certain circumstances.

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 (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 between 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.

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 GP and/or subordinated GP 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, has 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 its formation 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 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 its formation 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 incentivised 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. For example, in connection with the Partnership s proposed initial public offering, our interest would convert into 18,750,000 GP units and 16,000,000 subordinated GP interests. 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 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 its formation 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 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period, 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 directors and/or executive officers of CVR Energy. 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 CVR Energy or the Partnership.

48

Table of Contents

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.

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.

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.

As discussed elsewhere, the Partnership has filed a registration statement with the SEC in order to offer and sell a portion of its common units to the public. There can be no assurance that any such offering will be consummated. However, if such offering is consummated, the negative consequences described above would apply to our interest in the Partnership.

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.

Under the contribution, conveyance and assumption agreement, 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, if the Partnership is treated as a corporation for U.S. income tax purposes, this would substantially reduce the cash it has available to make distributions. In return for the receipt of the net cash proceeds, we would no longer receive quarterly distributions on the units that were sold which could negatively impact our financial position. Moreover, because we would own a smaller percentage of the total units of the Partnership after such sale or redemption, the percentage of distributions that we would receive from the Partnership would decrease. See 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.

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 the 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.

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.

Table of Contents

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. The nitrogen fertilizer business 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 nitrogen fertilizer business 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 limited partnership structure depends largely on its being treated as a partnership for federal income tax purposes. Despite the fact that the Partnership is 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 federal income tax purposes. If the Partnership consummates its proposed initial public offering in 2008, current law will require the Partnership to derive at least 90% of its annual gross income for 2008, and in each taxable year thereafter, from specific activities to continue to be treated as a partnership for federal income tax purposes. The Partnership may not find it possible to meet this income requirement, or may inadvertently fail to meet this income requirement.

Although we do not believe based upon the Partnership s current operations that it should be so treated, a change in the nitrogen fertilizer business or a change in current law 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 nitrogen fertilizer business is considering, and may consider in the future, expanding or entering into new activities or businesses. If legal counsel is unable to opine that gross income from any of these activities or businesses will count toward satisfaction of the 90% income, or qualifying income, requirement to be treated as a partnership, the Partnership may seek a ruling from the IRS that gross income it earns from those activities will be qualifying income. There can be no assurance that the IRS would issue a favorable ruling. If the Partnership does not receive a favorable ruling it may choose to engage in the activity through a corporate subsidiary, which would subject the income related to such activity to entity-level taxation. The Partnership has not requested, and does not plan to request, a ruling from the IRS on any other matter affecting the nitrogen fertilizer business.

In order for the Partnership to consummate an initial public offering, the Partnership will be required to 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 federal income tax purposes following such initial public offering. 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. If the Partnership is unable to obtain such an opinion, the Partnership will not consummate an initial public offering and will not be able to realize the anticipated benefits of being a master limited partnership.

If the Partnership were to be treated as a corporation for federal income tax purposes, it would pay 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 after-tax return to us.

In addition, current law could change so as to cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject it to entity-level taxation. For example, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to the Partnership as currently proposed, 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.

In addition, the sale of the managing general partner interest of the Partnership in a newly formed entity controlled by the Goldman Sachs Funds and the Kelso Funds was made at the fair market value of the 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 will be subject to tax. If the Internal Revenue Service 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 Internal Revenue Service or another taxing authority. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in the Partnership s common units. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the Partnership to taxation as a corporation or otherwise subjects it to entity-level taxation for federal, state or local income tax purposes, then Fertilizer GP may, in its sole discretion, cause the minimum quarterly distribution amount and the target distribution amounts to be adjusted to reflect the impact of that law on the Partnership.

If the Partnership consummates an initial public offering 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. 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.

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.

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

The present federal income tax treatment of publicly traded partnerships may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of our investment in the Partnership.

If the IRS contests the federal income tax positions the Partnership takes, the cost of any IRS contest will reduce the Partnership s cash available for distribution to unitholders.

Except as described above we have not and do not intend to request a ruling from the IRS with respect to the treatment of the Partnership as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the Partnership s counsel s conclusions or from the positions the Partnership takes. It may be necessary to resort to administrative or court proceedings to sustain some or all of the Partnership s counsel s conclusions or the positions the Partnership takes. A court may not agree with some or all of the Partnership s counsel s conclusions or the positions the Partnership takes. Any such contest will result in a reduction in cash available for distribution.

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

The Partnership will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in its capital and profits within a twelve-month period. The Partnership s termination would, among other things, result in the closing of its taxable year for all unitholders, which would result in the Partnership filing two tax returns (and its unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing the Partnership s taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of the Partnership s taxable income or loss being includable in his taxable income for the year of termination. The Partnership s termination currently would not affect its classification as a partnership for federal income tax purposes, but instead, the Partnership would be treated as a new partnership for tax purposes. If treated as a new partnership, the Partnership must make new tax elections and could be subject to penalties if it is unable to determine that a termination occurred.

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 also collectively beneficially own approximately 73% of our common stock as of December 31, 2007. 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.

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 found acceptable. 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. 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, we believe that the value of CVR Energy s common stock could also be affected. Because we have observed that entities structured as master limited partnerships have over recent history demonstrated significantly greater relative market valuation levels compared to corporations in the refining and marketing sector when measured as a ratio of enterprise value to EBITDA, we believe that the value of CVR Energy s common stock may be enhanced to the extent that the Partnership consummates an initial public offering, because then the public market valuation of CVR Energy s common stock would reflect the higher potential valuation of the Partnership realized in its offering. If the Partnership does not consummate an initial public offering, we believe CVR Energy s common stock may not reflect the higher potential valuation of a master limited partnership.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

The following table contains certain information regarding our principal properties:

Location	Acres	Own/Lease	Use
Coffeyville, KS	440	Own	CVR Energy: oil refinery and office buildings Partnership: fertilizer plant
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 October 2007, we transferred ownership of certain parcels of land, including land that the nitrogen fertilizer plant is situated on, to the Partnership so that the Partnership would be able to operate the nitrogen fertilizer plant on its own land. Additionally, in October 2007, we entered into a cross easement agreement with the Partnership so that both we and the Partnership would 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.

As of December 31, 2007, we had storage capacity for 767,000 barrels of gasoline, 1,068,000 barrels of distillates, 1,004,000 barrels of intermediates and 3,194,000 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 2,000,000 barrels of storage at Cushing, Oklahoma.

Item 3. *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 under Business 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.

(1) Class Action Suits

As a result of the crude oil discharge on or about July 1, 2007, two putative class action lawsuits (one federal and one state) were filed against us and/or our subsidiaries in July 2007.

(a) Federal Suit

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 No. 07-CV-01186-JTM-DWB). Plaintiff s complaint 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.

(b) State Suit

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 No. 07CV99I). This 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. To date no other lawsuits have been filed as a result of flood related damages.

(2) EPA Administrative Order on Consent

On July 10, 2007, we entered into an administrative order on consent 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. The

Table of Contents

Consent Order is described in further detail in Business Flood and Crude Oil Discharge EPA Administrative Order and Consent.

Item 4. ***Submission of Matters to a Vote of Security Holders***

On October 16, 2007, our stockholders, consisting of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, consented to the following actions by written consent:

- the election of the current members of our board of directors, effective as of October 16, 2007;
- the adoption of our Amended and Restated Certificate of Incorporation, dated October 16, 2007, and our Amended and Restated By-Laws;
- the adoption of the CVR Energy, Inc. 2007 Long Term Incentive Plan;
- the grant of options to purchase 5,150 shares of our common stock to each of Messrs. Regis B. Lippert and Mark Tomkins;
- the grant of 5,000 shares of nonvested stock to Mr. Lippert and the grant of 12,500 shares of nonvested stock to Mr. Tomkins; and
- the grant of 50 shares of our common stock to 542 of our employees (27,100 shares in total).

PART II

Item 5. ***Market For Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Use of Proceeds

On October 22, 2007 the SEC declared effective our registration statements on Form S-1 (Registration Nos. 333-137588) related to our sale of 23,000,000 shares of our common stock. On October 26, 2007, we completed an initial public offering of 23,000,000 shares at a price of $19.00 per share for an aggregate offering price of approximately $437.0 million. Of the aggregate gross proceeds, approximately $11.4 million was used to pay offering expenses related to the initial public offering, and $28.5 million was used to pay underwriting discounts and commissions. None of the expenses incurred and paid by us in the initial public offering were direct or indirect payments (i) to our directors, officers, general partners or their associates, (ii) to persons owning 10% or more of any class of our equity securities, or (iii) to our affiliates (except that a portion of the underwriters commission was paid to Goldman, Sachs & Co., a joint bookrunning manager of the offering and an affiliate of the Goldman Sachs Funds which own 36.5% of our common stock). Net proceeds of the offering after payment of expenses and underwriting discounts and commission were approximately $397.1 million.

The offering was made through an underwriting syndicate led by Goldman, Sachs & Co., Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC, Citigroup Global Markets Inc. and Simmons & Company International as joint book-running managers.

We used the net proceeds from the offering as follows:

- payment of term debt of $280.0 million and related interest of approximately $5.7 million;

repayment of $25 million under the unsecured credit facility and repayment of $25.0 million under the secured facility including related interest of approximately $0.2 million;

repayment of revolver borrowings of $50.0 million;

payment of a $5.0 million termination fee to each of Goldman, Sachs & Co. and Kelso & Company, L.P. in connection with the termination of the management agreements in conjunction with the initial public offering; and

$1.2 million was used for general corporate purposes.

Market Information

Our common stock is listed on the New York Stock Exchange under the symbol CVI and commenced trading on October 23, 2007. The table below sets forth, for the quarter indicated, the high and low sales prices per share of our common stock:

2007:	**High**	**Low**
Fourth Quarter (October 23, 2007 to December 31, 2007)	$ 26.25	$ 19.80

Holders of Record

As of March 5, 2008, there were 476 stockholders of record of our common stock. 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.

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 contained in the instruments governing future indebtedness that we or our subsidiaries may incur in the future.

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 IDRs which, over time, will give it rights to receive distributions. These provisions limit the amount of distributions which the Partnership can make to us which, in turn, limit our ability to make distributions to our stockholders. In addition, since the Partnership makes its distributions to CVR Special GP, LLC, which is controlled by Coffeyville Resources, LLC, a subsidiary of ours, our credit facility limits the ability of Coffeyville Resources 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.

On December 28, 2006, the directors of Coffeyville Acquisition LLC, which at that time operated our business, approved a special dividend of $250 million to its members, including $244.7 million to companies related to the Goldman Sachs Funds and the Kelso Funds and $3.4 million to certain members of our management and a director who had previously made capital contributions to Coffeyville Acquisition LLC.

In connection with our initial public offering, the directors of Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC, respectively, which at that time were our only stockholders, 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 management, a director and an unrelated member. The common unitholders receiving this special dividend contributed $10.6 million collectively to Coffeyville Acquisition III LLC, which used such amount to purchase the Partnership s managing general partner.

Table of Contents

Stock Performance Graph

The following graph sets forth the cumulative return on our common stock between October 23, 2007, the date on which our stock commenced trading on the NYSE, and December 31, 2007, as compared to the cumulative return of the Standard & Poor s 500 Index and an industry peer group consisting of Holly Corporation, Frontier Oil Corporation and Western Refining, Inc. The graph assumes an investment of $100 on October 23, 2007 in our common stock, the S&P 500 and the industry peer group, and assumes the reinvestment of dividends where applicable. The closing market price for our common stock on December 31, 2007 was $24.94. The stock price performance shown on the graph is not intended to forecast and does not necessarily indicate future price performance.

COMPARISON OF CUMULATIVE TOTAL RETURN
BETWEEN OCTOBER 23, 2007 AND DECEMBER 31, 2007
among CVR Energy, Inc., S&P 500 and a peer group

This performance graph shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of the Company under the Securities Act or the Exchange Act.

Unregistered Sales of Equity Securities

Prior to our initial public offering, we issued 247,471 shares of our common stock to our chief executive officer. The issuance of these shares of common stock was made pursuant to an exemption from registration provided by Rule 701 under the Securities Act of 1933, as amended.

Equity Compensation Plans

The table below contains information about securities authorized for issuance under our long term incentive plan as of December 31, 2007. This plan was approved by our stockholders in October 2007.

Plan	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
CVR Energy, Inc. Long Term Incentive Plan	18,900	$ 21.61	7,463,600

Table of Contents

Item 6. *Selected Financial Data*

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 Report.

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 Report, 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 Report.

Prior to March 3, 2004, our assets consisted of one facility within the eight-plant Nitrogen Fertilizer Manufacturing and Marketing Division of Farmland Industries, Inc. 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. 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.

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 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 Report. 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.

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 Report. 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 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.

We calculate earnings per share in 2006 and 2007 on a pro forma basis. This calculation gives effect to the issuance of 23,000,000 shares in our initial public offering, the merger of two subsidiaries of Coffeyville Acquisition, LLC with two of our direct wholly owned subsidiaries, the 628,667.20 for 1 stock split, the issuance of 247,471 shares of our common stock to our chief executive officer in exchange for his shares in

Table of Contents

two of our subsidiaries, the issuance of 27,100 shares of our common stock to our employees and the issuance of 17,500 non-vested restricted shares of our common stock to two of our directors. The weighted average shares outstanding for 2006 also gives effect to an increase in the number of shares which, when multiplied by the initial public offering price, would be sufficient to replace the capital in excess of earnings withdrawn, as a result of our paying dividends in the year ended December 31, 2006 in excess of earnings for such period, or 3,075,194 shares.

We have omitted earnings per share data for Immediate Predecessor because we operated under a different capital structure than what we currently operate under 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.

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.

	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**
Statement of Operations Data:							
Net sales	$ 1,262.2	$ 261.1	$ 1,479.9	$ 980.7	$ 1,454.3	$ 3,037.6	$ 2,966.9
Cost of product sold (exclusive of depreciation and amortization)	1,061.9	221.4	1,244.2	768.0	1,168.1	2,443.4	2,291.1
Direct operating expenses (exclusive of depreciation and amortization)	133.1	23.4	117.0	80.9	85.3	199.0	276.1
Selling, general and administrative expenses (exclusive of depreciation and amortization)	23.6	4.7	16.3	18.4	18.4	62.6	93.1
Net costs associated with flood(1)							41.5
Depreciation and amortization	3.3	0.4	2.4	1.1	24.0	51.0	60.8
	10.9						

Impairment, earnings (losses) in joint ventures, and other charges(2)							
Operating income	$ 29.4	$ 11.2	$ 100.0	$ 112.3	$ 158.5	$ 281.6	$ 204.3
Other income (expense)(3)	(0.5)		(6.9)	(8.4)	0.4	(20.8)	0.2
Interest (expense)	(1.3)		(10.1)	(7.8)	(25.0)	(43.9)	(61.1)
Gain (loss) on derivatives	0.3		0.5	(7.6)	(316.1)	94.5	(282.0)
Income (loss) before income taxes	$ 27.9	$ 11.2	$ 83.5	$ 88.5	$ (182.2)	$ 311.4	$ (138.6)
Income tax (expense) benefit			(33.8)	(36.1)	63.0	(119.8)	81.6
Minority interest in (income) loss of subsidiaries							0.2
Net income (loss)(4)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ (56.8)
Pro forma earnings per share, basic						$ 2.22	$ (0.66)
Pro forma earnings per share, diluted						$ 2.22	$ (0.66)
Pro forma weighted average shares, basic						86,141,291	86,141,291
Pro forma weighted average shares, diluted						86,158,791	86,141,291
Historical dividends:							
Preferred per unit(5)			$ 1.50	$ 0.70			
Common per unit(5)			$ 0.48	$ 0.70			
Management common units subject to redemption						$ 3.1	
Common units						$ 246.9	

	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
nce Sheet Data:							
and cash equivalents	$ 0.0		$ 52.7		$ 64.7	$ 41.9	$ 30
ing capital(6)	150.5		106.6		108.0	112.3	2
assets	199.0		229.2		1,221.5	1,449.5	1,850
ities subject to compromise(7)	105.2						
debt, including current portion			148.9		499.4	775.0	500
rity interest in subsidiaries(8)						4.3	10
gement units subject to redemption					3.7	7.0	
ional/members /stockholders equity	58.2		14.1		115.8	76.4	44
r Financial Data:							
eciation and amortization	$ 3.3	$ 0.4	$ 2.4	$ 1.1	$ 24.0	$ 51.0	$ 6
ncome adjusted for unrealized gain s from Cash Flow Swap(9)	27.9	11.2	49.7	52.4	23.6	115.4	
flows provided by operating ties	20.3	53.2	89.8	12.7	82.5	186.6	14
flows (used in) investing activities	(0.8)		(130.8)	(12.3)	(730.3)	(240.2)	(26
flows provided by (used in) cing activities	(19.5)	(53.2)	93.6	(52.4)	712.5	30.8	11
al expenditures for property, plant quipment	0.8		14.2	12.3	45.2	240.2	26
Operating Statistics:							
leum Business							
ction (barrels per day)(10)(11)	95,701	106,645	102,046	99,171	107,177	108,031	86,2
e oil throughput (barrels per 10)(11)	85,501	92,596	90,418	88,012	93,908	94,524	76,2
gen Fertilizer Business							
ction Volume:							
onia (tons in thousands)(11)	335.7	56.4	252.8	193.2	220.0	369.3	32
(tons in thousands)(11)	510.6	93.4	439.2	309.9	353.4	633.1	57
eam factors (12):							
ier	90.1%	93.5%	92.2%	97.4%	98.7%	92.5%	9
onia	89.6%	80.9%	79.7%	95.0%	98.3%	89.3%	8
	81.6%	88.7%	82.2%	93.9%	94.8%	88.9%	7

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

(2) 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.

(3) 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.

(4) 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	Year Ended December 31, 2007
Impairment of property, plant and equipment(a)	$ 9.6	$	$	$	$	$	$
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
Major scheduled turnaround expense(e)			1.8			6.6	76.4
Loss on termination of swap(f)					25.0		
Unrealized (gain) loss from Cash Flow Swap					235.9	(126.8)	103.2

(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 $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004, 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.

(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.

(5) 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.

(6) 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.

(7) 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.

(8) 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 CALLC III s ownership of the managing general partner interest and IDR s of the Partnership.

(9) Net income adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for 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 by Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if 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 January 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.

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 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 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 adjusted for 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 U.S. GAAP net income results as well as Net income adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income 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 adjusted for 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 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 adjusted for unrealized gain or loss from Cash Flow Swap to Net income:

	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
Net income adjusted for unrealized gain (loss) from Cash Flow Swap	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ 23.6	$ 115.4	$ 5.2
Plus:							
Unrealized gain (loss) from Cash Flow Swap, net of tax benefit					(142.8)	76.2	(62.0)
Net income (loss)	$ 27.9	$ 11.2	$ 49.7	$ 52.4	$ (119.2)	$ 191.6	$ (56.8)

(10) 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.

(11) 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.

(12) 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 in 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN.

Item 7. *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 Report.

Forward-Looking Statements

This Annual Report on Form 10-K for the year ended December 31, 2007 (the Report), including without limitation the sections captioned Business and Management s Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements as defined by the Securities & Exchange Commission (the SEC).

Such statements are those concerning contemplated transactions and strategic plans, expectations and objectives for future operations. These include, without limitation:

- statements, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future;

- statements relating to future financial performance, future capital sources and other matters; and

- any other statements preceded by, followed by or that include the words anticipates, believes, expects, plans, intends, estimates, projects, could, should, may, or similar expressions.

Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Report are reasonable, we can give no assurance that such plans, intentions or expectations will be achieved. These statements are based on assumptions made by us based on our experience and perception of historical trends, current conditions, expected future developments and other factors that we believe are appropriate in the circumstances. Such statements are subject to a number of risks and uncertainties, many of which are beyond our control. You are cautioned that any such statements are not guarantees of future performance and that actual results or developments may differ materially from those projected in the forward-looking statements as a result of various factors, including but not limited to those set forth under Risk Factors and contained elsewhere in this Report.

All forward-looking statements contained in this Report only speak as of the date of this document. We undertake no obligation to update or revise publicly any forward-looking statements to reflect events or circumstances that occur after the date of this Report, or to reflect the occurrence of unanticipated events.

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 80% of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

Petroleum business. Our petroleum business includes a 113,500 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 southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, and (3) 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 Coffeyville 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 peak daily rates in excess of 120,000 bpd in 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 purchase cost discount to WTI from $3.33 per barrel in 2005 to $4.75 per barrel in 2006 and $4.82 per barrel in 2007.

Prior to July 2005, we did not maintain shipper status on the Magellan pipeline system. Instead, rack marketing was limited to our owned terminals. While we still rack market at our own terminals, our growing rack marketing network sells approximately 23% of produced transportation fuels at enhanced margins.

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 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. Its redundant train gasifier provides good on-stream reliability and the use of low cost by-product pet coke feed (rather than natural gas) to produce hydrogen provides the facility with a significant competitive advantage due to 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 and developed 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), the majority of which has already been spent. 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 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 $85 million fertilizer plant expansion, of which approximately $8 million was incurred as of December 31, 2007. We estimate this expansion will increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium-priced UAN by approximately 50%. The nitrogen fertilizer business currently expects to complete this expansion in late 2009 or early 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.

Table of Contents

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. 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 million of our outstanding term loan debt and to repay in full the $25 million secured credit facility and the $25 million unsecured credit facility. We also repaid $50 million of indebtedness under our revolving credit facility. Associated with the repayment of the $25 million secured facility and the $25 million unsecured facility, we recorded a write-off of unamortized deferred financing fees of approximately $1.3 million in the fourth quarter of 2007.

In connection with the initial public offering, we also became the indirect owner of Coffeyville Resources, LLC and all of its refinery assets and its interest in the nitrogen fertilizer business. This was accomplished by the issuance of 62,866,720 shares of our common stock to certain entities controlled by our majority stockholder 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 nonvested shares issued.

CVR Partners Proposed Initial Public Offering

On February 28, 2008, the Partnership filed a registration statement with the SEC to effect an initial public offering of 5,250,000 common units representing limited partner interests. The Partnership intends to apply to the NYSE to list its common units. If the Partnership s initial public offering is consummated on the proposed terms, the 30,303,000 special GP units and 30,333 special LP units which we indirectly own will convert into 18,750,000 GP units and 16,000,000 subordinated GP units of the Partnership, and as a result, we will indirectly own approximately 87% of the outstanding units of the Partnership. The registration statement also provides that the net proceeds from the Partnership s initial public offering will be used to reimburse Coffeyville Resources for certain capital expenditures made on the Partnership s behalf prior to October 24, 2007 (approximately $18.4 million) and to pay financing fees in connection with entering into a new revolving credit facility (approximately $2.5 million) with the remainder to be retained by the Partnership to fund working capital and future capital expenditures of its business, including the ongoing expansion of the nitrogen fertilizer plant (approximately $85 million). There can be no assurance that any such offering will be consummated on the terms described in the registration statement or at all.

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.

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 NYMEX gasoline and heating oil against the market value of NYMEX WTI (WTI) crude oil (West Texas Intermediate crude oil, which is used as a benchmark for other crude oils), 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 distillate.

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 WTS differential to WTI and the Maya differential to WTI as both these differentials indicate the relative price of heavier, more sour, slate to WTI. 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. The WTI less Maya crude oil differential was $15.67, $14.99 and $12.54 per barrel, for the years ended December 31, 2005, 2006 and 2007, respectively. The WTI less WTS crude oil differential was $4.73, $5.36 and $5.16 per barrel for the years ended December 31, 2005, 2006 and 2007, respectively. The Company s consumed crude differential increased to $4.54 per barrel for the year ended December 31, 2006 from $3.28 per barrel for the comparable period in 2005 and decreased to $2.82 for the year ended December 31, 2007 from $4.54 for the same period in 2006. The consumed crude differential for 2007 is not comparable to prior periods due to the refinery-wide turnaround we undertook in the first quarter of 2007 and the 2007 flood.

We produce a high volume of high value products, such as gasoline and distillates. 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. Both gasoline and heating oil basis are greater than zero, which represents that prices in our marketing area exceeds those used in the 2-1-1 crack spread. Since 2003, the heating oil basis has been positive in all periods presented, including an increase to $7.95 per barrel for 2007 from $7.42 per barrel in 2006 and $3.20 per barrel for 2005. The increase for 2006 was significantly impacted by the introduction of Ultra Low Sulfur Diesel. Gasoline basis for 2007 was $3.56 per barrel, compared to $1.52 per barrel in 2006 and ($0.53) per barrel for 2005. Beginning January 1, 2007, the benchmark used for gasoline was changed from Reformulated Gasoline (RFG) to

Reformulated Blend for Oxygenate Blend (RBOB).

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 the needed maintenance, feedstock logistics and other factors.

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 (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 coke supply agreement we entered into in October 2007. 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.

Natural gas is the most significant raw material required in the production of most nitrogen fertilizers. North American natural gas prices have increased substantially and, since 1999, have become significantly more volatile. In 2005, North American natural gas prices reached unprecedented levels due to the impact hurricanes Katrina and Rita had on an already tight natural gas market. Recently, natural gas prices have moderated, returning to pre-hurricane levels or lower.

In order to assess the operating performance of the nitrogen fertilizer business, we calculate plant gate price to determine our operating margin. Plant gate price refers to the unit price of fertilizer, in dollars per ton, offered on a delivered basis, excluding shipment costs. Given the use of low cost pet coke, the nitrogen fertilizer business is not presently subjected to the high raw materials costs of competitors that use natural gas, the cost of which has been high in recent periods. Instead of experiencing high variability in the cost of raw materials, the nitrogen fertilizer business utilizes less than 1% of the natural gas relative to other natural gas-based fertilizer producers and we estimate that the nitrogen fertilizer business would continue to have a production cost advantage in comparison to U.S. Gulf Coast ammonia producers at natural gas prices as low as $2.50 per MMBtu. The spot price for natural gas at Henry Hub on December 31, 2007 was $7.48 per MMBtu.

Because the nitrogen fertilizer plant has certain logistical advantages relative to end users of ammonia and UAN and demand relative to production has remained high, the nitrogen fertilizer business primarily targeted end users in the U.S. farm belt where it incurs lower freight costs as compared to competitors. The farm belt refers to the states of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas and Wisconsin. The nitrogen fertilizer business does not incur any intermediate storage, barge or pipeline freight charges when it sells in these markets, giving us a distribution cost advantage over U.S. Gulf Coast importers, assuming freight rates and pipeline tariffs for U.S. Gulf Coast importers as recently in effect. Selling products to customers within economic rail transportation limits of the nitrogen fertilizer plant and keeping transportation costs low are keys to maintaining profitability.

The value of nitrogen fertilizer products is also an important consideration in understanding our results. During 2007, the nitrogen fertilizer business upgraded approximately 72% 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.

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 fixed operating expenses include electrical energy, employee labor, maintenance, including contract labor, and outside services. These costs comprise the fixed costs associated with the nitrogen fertilizer plant. Variable costs associated with the nitrogen fertilizer plant have averaged approximately 1.2% of direct operating expenses over the 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.

Consistent, safe, and reliable operations at the nitrogen fertilizer plant are critical to its financial performance and results of operations. Unplanned downtime of the nitrogen fertilizer plant may result in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position. The financial impact of planned downtime, such as major turnaround maintenance, is mitigated through a diligent planning process that takes into account margin environment, the availability of resources to perform the needed maintenance, feedstock logistics and other factors.

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

Table of Contents

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 mentioned above, 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; 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 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. Historically, 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 the past three years, the new 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 reducing 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.

Factors Affecting Comparability

Our historical results of operations for the periods presented may not be comparable with prior periods or to our results of operations in the future for the reasons discussed below.

2007 Flood and Crude Oil Discharge

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. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were flooded, sustained major damage and required repairs.

Total costs incurred and recorded as of December 31, 2007 related to third party costs to repair the refinery and fertilizer facilities were approximately $79.2 million and $3.5 million, respectively. In addition, we currently estimate that approximately $6.0 million in third party costs related to the repair of flood damaged property will be recorded in future periods.

As a result of the flooding, our refinery and nitrogen fertilizer facilities stopped operating on June 30, 2007. 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. Production at the nitrogen fertilizer facility was restarted on July 13, 2007.

In addition, 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 are currently remediating the contamination caused by the crude oil discharge. Total net costs recorded as of December 31, 2007 associated with remediation efforts and third party property damage incurred by the crude oil discharge are approximately $23.5 million. This amount is net of anticipated insurance recoveries of $21.4 million. As of December 31, 2007, we received $10.0 million of insurance proceeds under our insurance policies. 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 class action lawsuits related to the flood.

Our results for the year ended December 31, 2007 include pretax costs of $41.5 million associated with the flood and related crude oil discharge. This amount is net of anticipated insurance recoveries of $85.3 million. We anticipate that approximately $6.0 million in third party costs related to the repair of the flood damaged property will be recorded in future periods.

The 2007 flood and crude oil discharge had a significant adverse impact on our financial results for the year ended December 31, 2007. We reported reduced revenue due to the closure of our facilities for a portion of the third quarter, as well as significant costs related to the flood as a result of the necessary repairs to our facilities and environmental remediation. See Business Flood and Crude Oil Discharge.

Refinancing and Prior Indebtedness

Effective May 10, 2004, Immediate Predecessor entered into a term loan of $150 million and a $75 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. 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 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 million, consisting of $225 million tranche B term loans; $50 million of delayed draw term loans available for the first 18 months of the agreement and subject to accelerated payment terms; a $100 million revolving loan facility; and a funded letter of credit facility (funded facility) of $150 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 million of tranche B term loans were refinanced with $225 million of tranche C term loans. The second lien credit facility was a $275 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 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 million of tranche D term loans, a $150 million revolving credit facility, and a funded letter of credit facility of $150 million issued in support of the Cash Flow Swap. The credit facility is secured by substantially all of Coffeyville Resources, LLC s assets. 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.

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 million secured facility, a $25 million unsecured facility and a $75 million unsecured facility. No amounts were drawn under the $75 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 million of term debt with initial public offering proceeds. Additionally, we repaid the $25 million secured facility and $25 million unsecured facility in their entirety with a portion of the net proceeds from the initial public offering. Also, the $75 million credit facility terminated upon consummation of the initial public offering.

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 & Company (J. Aron) with respect to the Cash Flow Swap, which is a series of commodity derivative arrangements whereby if crack spreads fall below a fixed level, J. Aron agreed to pay the difference to us, and if crack spreads 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.

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, Inc. as a result of a series of steps. 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. The majority of these costs were expenses 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, but had very little impact on our 2006 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 Report. 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. The Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 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. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under Statement of Financial Accounting Standards (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.

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 December 31, 2007, 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 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 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. 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 Gulf Coast producers and our gasification process requires less than 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 February 2008 that total U.S. planted corn acreage in 2008 will decline to 88 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.

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

Table of Contents

comparing 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 corporate selling, general and administrative allocation method 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.

The following table provides an overview of our results of operations during the past three fiscal years:

Consolidated Financial Results	Immediate Predecessor 174 Days Ended June 23, 2005	Successor 233 Days Ended December 31, 2005	Year Ended December 31, 2006	2007
	(in millions)			
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	2,291.1
Direct operating expenses (exclusive of depreciation and amortization)	80.9	85.3	199.0	276.1
Selling, general and administrative expense (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	$ 204.3
Net income (loss)(3)	52.4	(119.2)	191.6	(56.8)
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(4)	52.4	23.6	115.4	5.2

(1) Represents the write-off of approximate net costs associated with the flood and crude oil spill that are not probable of recovery. See Business 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
	(in millions)			
Depreciation and amortization excluded from cost of product sold	$ 0.1	$ 1.1	$ 2.2	$ 2.4
Depreciation and amortization excluded from direct operating expenses	0.9	22.7	47.7	57.4
Depreciation and amortization excluded from selling, general and administrative expense	0.1	0.2	1.1	1.0
Depreciation included in net costs associated with flood				7.6

Total depreciation and amortization	$ 1.1	$ 24.0	$ 51.0	$ 68.4

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:

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
	(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
Major scheduled turnaround expense(d)			6.6	76.4
Loss on termination of swap(e)		25.0		
Unrealized (gain) loss from Cash Flow Swap		235.9	(126.8)	103.2

(a) Represents the write-off of $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004, 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 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.

(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 adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for 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 crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if

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 January 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.

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 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 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 adjusted for 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 U.S. GAAP net income results as well as Net income adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income 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 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 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 adjusted for unrealized gain or loss from Cash Flow Swap to Net income:

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**
		(in millions)		
Net Income adjusted for unrealized gain or loss from Cash Flow Swap	$ 52.4	$ 23.6	$ 115.4	$ 5.2
Plus:				
Unrealized gain or (loss) from Cash Flow Swap, net of taxes		(142.8)	76.2	(62.0)
Net income (loss)	$ 52.4	$ (119.2)	$ 191.6	$ (56.8)

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 $2,291.1 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 $152.3 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 $204.3 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 $83.1 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 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 $81.6 million, or 59% of loss before income taxes, as compared to income tax expense of $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 $56.8 million as compared to net income of $191.6 million for the year ended December 31, 2006. Net income decreased $248.4 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.

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 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 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	Successor 233 Days Ended December 31, 2005	Successor Year Ended December 31, 2006	Successor Year Ended December 31, 2007
	(in millions)			
Petroleum Business:				
Net sales	$ 903.8	$ 1,363.4	$ 2,880.4	$ 2,806.2
Cost of product sold (exclusive of depreciation and amortization)	761.7	1,156.2	2,422.7	2,282.6
Direct operating expenses (exclusive of depreciation and amortization)	52.6	56.2	135.3	209.5
Net costs associated with flood				36.7
Depreciation and amortization	0.8	15.6	33.0	43.0
Gross profit (loss)	$ 88.7	$ 135.4	$ 289.4	$ 234.4
Plus direct operating expenses (exclusive of depreciation and amortization)	52.6	56.2	135.3	209.5
Plus net costs associated with flood				36.7
Plus depreciation and amortization	0.8	15.6	33.0	43.0
Refining margin	$ 142.1	$ 207.2	$ 457.7	$ 523.6
Refining margin per refinery throughput barrel	$ 9.28	$ 11.55	$ 13.27	$ 18.80
Gross profit (loss) per refinery throughput barrel	$ 5.79	$ 7.55	$ 8.39	$ 8.42

Direct operating expenses (exclusive of depreciation and amortization) per refinery throughput barrel	$ 3.44	$ 3.13	$ 3.92	$ 7.52
Operating income (loss)	76.7	123.0	245.6	162.5

	Immediate Predecessor and Successor Combined Year Ended December 31, 2005	Successor Year Ended December 31, 2006	Successor Year Ended December 31, 2007
		(dollars per barrel)	
Market Indicators			
West Texas Intermediate (WTI) crude oil	$ 56.70	$ 66.25	$ 72.36
NYMEX 2-1-1 Crack Spread	11.62	10.84	13.95
Crude Oil Differentials:			
WTI less WTS (sour)	4.73	5.36	5.16
WTI less Maya (heavy sour)	15.67	14.99	12.54
WTI less Dated Brent (foreign)	2.18	1.13	(0.02)
PADD II Group 3 versus NYMEX Basis:			
Gasoline	(0.53)	1.52	3.56
Heating Oil	3.20	7.42	7.95
PADD II Group 3 versus NYMEX Crack:			
Gasoline	10.53	12.26	18.34
Heating Oil	15.60	18.77	21.40
Company Operating Statistics			
Per barrel profit, margin and expense of crude oil throughput:			
Refining margin	$ 10.50	$ 13.27	$ 18.80
Gross profit	$ 6.74	$ 8.39	$ 8.42
Direct operating expenses (exclusive of depreciation and amortization)	3.27	3.92	7.52
Per gallon sales price:			
Gasoline	1.61	1.88	2.20
Distillate	1.71	1.99	2.28

Selected Company Volumetric Data	Immediate Predecessor and Successor Combined December 31, 2005 Barrels Per Day	%	Successor December 31, 2006 Barrels Per Day	%	Successor December 31, 2007 Barrels Per Day	%
Production:						
Total gasoline	45,275	43.8	48,248	44.7	37,017	42.9
Total distillate	39,997	38.7	42,175	39.0	34,814	40.4
Total other	18,090	17.5	17,608	16.3	14,370	16.7

Total all production	103,362	100.0	108,031	100.0	86,201	100.0
Crude oil throughput	91,097	92.6	94,524	92.1	76,285	93.0
All other inputs	7,246	7.4	8,067	7.9	5,780	7.0
Total feedstocks	98,343	100.0	102,591	100.0	82,065	100.0

Selected Company Volumetric Data	Immediate Predecessor and Successor Combined December 31, 2005 Total Barrels Per Day	%	Successor December 31, 2006 Total Barrels Per Day	%	Successor December 31, 2007 Total Barrels Per Day	%
Crude oil throughput by crude type:						
Sweet	13,958,567	42.0	17,481,803	50.7	18,190,459	65.3
Light/medium sour	19,291,951	58.0	16,695,173	48.4	6,465,368	23.2
Heavy sour			324,312	0.9	3,188,133	11.5
Total crude oil throughput	33,250,518	100.0	34,501,288	100.0	27,843,960	100.0

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 $2,282.6 million for the year ended December 31, 2007 compared to $2,422.7 million for the year ended December 31, 2006. The decrease of $140.1 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 $69.59, compared to $61.71 for the comparable period of 2006, an increase of 13%. 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 $62.6 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 $18.80 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 Coffeyville supply area) 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. Petroleum operating income was $162.5 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 $83.1 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 Report entitled Business 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 Coffeyville supply area) 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.

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**
		(in millions)		
Net sales	$ 79.3	$ 93.7	$ 162.5	$ 165.9
Cost of product sold (exclusive of depreciation and amortization)	9.1	14.5	25.9	13.0
Direct operating expenses (exclusive of depreciation and amortization)	28.3	29.2	63.7	66.7
Net costs associated with flood				2.4
Depreciation and amortization	0.3	8.4	17.1	16.8
Operating income	35.3	35.7	36.8	46.6

Market Indicators	Year Ended December 31, 2005	2006	2007
Natural gas (dollars per MMBtu)	$ 9.01	$ 6.98	$ 7.12
Ammonia Southern Plains (dollars per ton)	356	353	409
UAN Corn Belt (dollars per ton)	212	197	288

Company Operating Statistics	Immediate Predecessor and Successor Combined Year Ended December 31, 2005	Successor Year Ended December 31, 2006	Successor Year Ended December 31, 2007
Production (thousand tons):			
Ammonia	413.2	369.3	326.7
UAN	663.3	633.1	576.9
Total	1,076.5	1,002.4	903.6
Sales (thousand tons)(1):			
Ammonia	141.8	117.3	92.1
UAN	646.5	645.5	555.4
Total	788.3	762.8	647.5
Product pricing (plant gate) (dollars per ton)(1):			
Ammonia	$ 324	$ 338	$ 376
UAN	$ 173	$ 162	$ 211
On-stream factor(2):			
Gasifier	98.1%	92.5%	90.0%
Ammonia	96.7%	89.3%	87.7%
UAN	94.3%	88.9%	78.7%
Reconciliation to net sales (dollars in thousands):			
Freight in revenue	$ 15,010	$ 17,890	$ 13,826
Sales net plant gate	157,989	144,575	152,030
Total net sales	$ 172,999	$ 162,465	$ 165,856

(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 2006, the on-stream factors in 2006 would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN.

(3) Based on nameplate capacity of 1,100 tons per day.

(4) Based on nameplate capacity of 1,500 tons per day.

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.

Table of Contents

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.

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 partially 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. The transfer of hydrogen to our petroleum operations is scheduled to be replaced with hydrogen produced by the new continuous catalytic reformer scheduled to be completed in the fall of 2007. We do not expect this will be affected or changed due to our new Partnership structure for the nitrogen fertilizer business.

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 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 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.

Table of Contents

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operating activities, existing cash balances and our existing revolving credit facility. 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.

Our liquidity was enhanced during the fourth quarter of 2007 by the receipt of $408.5 million of net proceeds from our initial public offering after the payment of underwriting discounts and commissions, but before the deduction of offering expenses. We believe that our cash flows from operations, borrowings under our revolving credit facilities and other capital resources will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next 12 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.

Cash Balance and Other Liquidity

As of December 31, 2007, we had cash, cash equivalents and short-term investments of $30.5 million. As of December 31, 2007, we had no amounts outstanding under our revolving credit facility and aggregate availability of $110.6 million under our revolving credit facility.

As of December 31, 2007, our working capital and total stockholders equity were negatively impacted by the mark to market accounting treatment of the Cash Flow Swap. The payable to swap counterparty included in the consolidated balance sheet at December 31, 2007 was approximately $350.6 million, and the current portion included an increase of $225.5 million from December 31, 2006, resulting in an equal reduction in our working capital for that same period. The current portion of the payable to swap counterparty for the period ended December 31, 2007 includes $123.7 million of deferred payments to J. Aron due August 31, 2008. If the unrealized portion of this obligation becomes realized during 2008 and we are required to satisfy the obligations associated with the realized losses, assuming the plant is operating in a commercially reasonable manner, we believe we will have cash flows from operations sufficient to meet this obligation, as a result of the inherent nature of the Cash Flow Swap.

On June 30, 2007, our refinery and the nitrogen fertilizer plant were severely flooded and forced to conduct emergency shutdowns and evacuate. See Business 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 2007 flood and crude oil discharge. In order to provide adequate immediate and future liquidity, on August 23, 2007 we deferred payments of $123.7 million which were due to J. Aron under the terms of the Cash Flow Swap, borrowed $50 million under new credit facilities and put in place additional borrowing availability of $75 million. In connection with our initial public offering, we repaid all indebtedness under the new credit facilities, terminated all three new facilities, and the maturity of the J. Aron deferred amounts was extended to August 31, 2008. See Debt and Payment Deferrals Related to Cash Flow Swap for additional information about the new credit facilities and payment deferral.

At December 31, 2007, funded long-term debt, including current maturities, totaled $489.2 million of tranche D term loans. Other commitments at December 31, 2007 included a $150.0 million funded letter of credit facility and a $150.0 million revolving credit facility. As of December 31, 2007, the commitment outstanding on the revolving credit facility was $39.4 million, including $0 million in borrowings, $5.8 million in letters of credit in support of certain environmental obligations, $3.0 million in letters of credit 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.

Working capital at December 31, 2007 was $21.4 million, consisting of $557.8 million in current assets and $536.4 million in current liabilities. Working capital at December 31, 2006 was $112.3 million, consisting of $342.5 million in current assets and $230.2 million in current liabilities.

Debt

On December 28, 2006, our subsidiary Coffeyville Resources, LLC entered into a credit facility which provides financing of up to $1.075 billion. The credit facility consists of $775 million of tranche D term loans, a $150 million revolving credit facility, and a funded letter of credit facility of $150 million issued in support of the Cash Flow Swap. On October 26. 2007, we repaid $280 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 credit facility refinanced our then existing first lien credit facility and second lien credit facility, which were initially entered into on June 24, 2005 in conjunction with the Subsequent Acquisition. The first lien credit facility consisted of $225.0 million of tranche B term loans; $50 million of delayed draw term loans; a $100.0 million revolving loan facility; and a $150.0 million funded letter of credit facility issued in support of the Cash Flow Swap. The second lien credit facility consisted of a $275.0 million term loan. The first lien credit facility was amended and restated on June 29, 2006 on substantially the same terms as the June 24, 2005 agreement; the primary reason for the June 2006 amendment and restatement was to reduce the applicable margin spreads for borrowings on the first lien term loans and the funded letter of credit facility.

The $489.2 million of tranche D term loans outstanding as of December 31, 2007 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. Our first lien credit facility, now repaid in full, had a similar amortization schedule and prior to repayment in full we had made all of the quarterly principal amortization payments under that facility.

The revolving loan 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 loan 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 December 31, 2007, we had available $110.6 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 net proceeds of $775.0 million received on December 28, 2006 from the term loans under the credit facility were used to repay the term loans under our then existing first lien credit facility, repay all amounts outstanding under our then existing second lien credit facility, pay related fees and expenses, and pay a dividend to existing members of Coffeyville Acquisition LLC in the amount of $250 million.

The net proceeds received in June 2005 from the tranche B term loan of $225.0 million under our then-existing first lien credit facility, second lien term loans of $275.0 million, $12.5 million of revolving loan facilities and a

$227.7 million equity contribution from Coffeyville Acquisition LLC were utilized to fund the following upon the closing of the Subsequent Acquisition: (1) $685.8 million for cash proceeds to Immediate Predecessor ($1,038.9 million of assets acquired less $353.1 million of liabilities assumed), including $12.6 million of legal, accounting, advisory, transaction and other expenses associated with the Subsequent Acquisition; (2) $49.6 million of other fees and expenses related to the Subsequent Acquisition, including financing fees, risk management fees associated with option premiums for crack spread swaps, and title fees; and (3) $4.9 million of cash to fund our operating accounts.

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). Prior to the December 2006 amendment and restatement, first lien term loans accrued interest at (a) the greater of the prime rate and the federal funds rate plus 0.5%, plus in either case 1.25%, or, at the borrower s option, (b) LIBOR plus 2.25% (with potential stepdowns to LIBOR plus 2.00% or the prime rate plus 1.00%), and second lien term loans accrued interest at a rate of LIBOR plus 6.75% or, at the borrower s option, the prime rate plus 5.75%.

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). Prior to the December 2006 amendment and restatement, revolving loans under the then-existing first lien credit facility accrued interest at (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 1.50%, or, at the borrower s option, (b) LIBOR plus 2.50% (with potential stepdowns to LIBOR plus 2.00% or the prime rate plus 1.00%).

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;

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; and

100% of the cash proceeds received by us from any initial public offering or secondary registered offering of equity interests, until the aggregate amount of such proceeds is equal to $280 million.

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. Our initial public offering triggered a mandatory prepayment of the credit facility and, as a result, a portion of the net proceeds of our initial public offering were used to repay $280 million of term debt.

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
March 31, 2008	3.25:1.00	3.25:1.00
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 December 31, 2007, we were in compliance with our covenants under the credit facility.

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

Table of Contents

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) 2005 (unaudited)	Successor Year Ended December 31, 2006	2007
	(in millions)		
Net income (loss)	$ (66.8)	$ 191.6	$ (56.8)
Plus:			
Depreciation and amortization	25.1	51.0	68.4
Interest expense	32.8	43.9	61.1
Income tax expense (benefit)	(26.9)	119.8	(81.6)
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
Major scheduled turnaround expense		6.6	76.4
Loss on termination of Swap	25.0		
Unrealized (gain) or loss on derivatives	229.8	(128.5)	113.5
Non-cash compensation expense for equity awards	1.8	16.9	43.5
(Gain) or loss on disposition of fixed assets		1.2	1.3
Expenses related to acquisition	3.5		
Minority interest in subsidiaries			(0.2)
Management fees	2.3	2.3	11.7
Consolidated adjusted EBITDA	$ 253.6	$ 328.2	$ 240.4

In addition to the financial covenants summarized in the table above, the credit facility restricts the capital expenditures of Coffeyville Resources, LLC to $375 million in 2007, $125 million in 2008, $125 million in 2009, $80 million in 2010, and $50 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 ended 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 million, a breach or default with respect to material terms under other debt arrangements in an aggregate amount of at least $20 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 million, events relating to employee benefit plans resulting in liability in excess of $20 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 at least $250 million of gross proceeds and we used the proceeds of the offering to repay at least $275 million of term loans under the credit facility. As a result of our initial public offering constituting a 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 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 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 ended 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 deals with, among other things, priority of liens, payments and proceeds of sale of collateral.

New 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 (see Payment Deferrals Related to Cash Flow Swap). 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 Million Secured Facility. Coffeyville Resources, LLC entered into a new $25 million senior secured term loan (the $25 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 Million Unsecured Facility. Coffeyville Resources, LLC entered into a new $25 million senior unsecured term loan (the $25 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 Million Unsecured Facility. Coffeyville Refining & Marketing Holdings, Inc. entered into a new $75 million senior unsecured term loan (the $75 million unsecured facility). Drawings could be made from time to time in amounts of at least $5 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 million secured facility and the $25 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 but we will be required to use 37.5% of our consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferred amounts.

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 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 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 million payment due September 7, 2007 (and accrued interest), the $43.7 million payment due September 7, 2007 (and accrued interest) and the $35 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, we might sell interests in the offering or 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 facilities, as well as 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 facilities 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 facilities on terms satisfactory to us, we may need to refinance them 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 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 million minus the amount of capital expenditures it will reimburse us for from the proceeds of its initial public or private offering ($18.4 million) 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.

In addition, we may elect to sell our interests in the Partnership in a secondary public offering (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. 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.

The Partnership filed a registration statement with the SEC on February 28, 2008 in connection with an initial public offering of its limited partner interests. In connection with the proposed offering, we intend to ask the lenders under our credit facility as well as J. Aron to release the Partnership and its subsidiaries from this guarantee under our credit facility and the Cash Flow Swap. The registration statement is currently under SEC review and there can be no assurance that such offering 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 $274 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 facilities limit 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 $69 million in the aggregate between 2008 and 2010. These amounts are reflected in the table below under Environmental capital needs. See Business Environmental Matters Fuel Regulations Tier II, Low Sulfur Fuels.

Table of Contents

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 December 31, 2007 (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 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	$ 62.5	$ 33.0	$ 24.3	$ 2.6	$ 2.1	$ 390.9
Sustaining capital needs	11.8	14.9	28.4	22.3	22.5	21.0	21.5	142.4
	156.4	136.7	90.9	55.3	46.8	23.6	23.6	533.3
Major scheduled turnaround expenses	4.0	76.4			50.0			130.4
Total estimated non-discretionary spending	$ 160.4	$ 213.1	$ 90.9	$ 55.3	$ 96.8	$ 23.6	$ 23.6	$ 663.7

Nitrogen Fertilizer Business

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental and safety capital needs	$ 0.1	$ 0.5	$ 2.0	$ 4.7	$ 2.6	2.7	3.8	$ 16.4
Sustaining capital needs	6.6	3.9	8.9	3.2	4.5	4.8	4.3	36.2
	6.7	4.4	10.9	7.9	7.1	7.5	8.1	52.6
Major scheduled turnaround expenses	2.6		2.8		2.6		2.8	10.8
Total estimated non-discretionary spending	$ 9.3	$ 4.4	$ 13.7	$ 7.9	$ 9.7	$ 7.5	$ 10.9	$ 63.4

Combined

	2006	2007	2008	2009	2010	2011	2012	Cumulative
				(in millions)				
Environmental and safety capital needs	$ 144.7	$ 122.3	$ 64.5	$ 37.7	$ 26.9	5.3	5.9	$ 407.3

Sustaining capital needs	18.4	18.8	37.3	25.5	27.0	25.8	25.8	178.6
	163.1	141.1	101.8	63.2	53.9	31.1	31.7	585.9
Major scheduled turnaround expenses	6.6	76.4	2.8		52.6		2.8	141.2
Total estimated non-discretionary spending	$ 169.7	$ 217.5	$ 104.6	$ 63.2	$ 106.5	$ 31.1	$ 34.5	$ 727.1

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 $36 million per year between 2008 and 2012.

The Partnership is currently moving forward with an approximately $85 million fertilizer plant expansion, of which approximately $8 million was incurred as of December 31, 2007. We estimate this expansion will increase the nitrogen fertilizer plant s capacity to upgrade ammonia into premium priced UAN by approximately 50%. The Partnership currently expects to complete this expansion in late 2009 or early 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 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)			
Net cash provided by (used in)				
Operating activities	$ 12.7	$ 82.5	$ 186.6	$ 145.9
Investing activities	(12.3)	(730.3)	(240.2)	(268.6)
Financing activities	(52.4)	712.5	30.8	111.3
Net increase (decrease) in cash and cash equivalents	$ (52.0)	$ 64.7	$ (22.8)	$ (11.4)

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 its proposed initial public offering. See Risk Factors Risks Related to the Limited Partnership Structure Through Which We Will 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 the quarterly distributions to us following the payment of expenses and fees and the establishment of cash reserves.

Cash Flows Provided by Operating Activities

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 $60.6 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 $79.6 million resulting in a net use of cash of $96.6 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 $36.0 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 $56.9 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. 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

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.

Cash Flows Provided by Financing Activities

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.

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 December 31, 2007 relating to long-term debt, operating leases, unconditional purchase obligations and other specified capital and commercial commitments for the five-year period following December 31, 2007 and thereafter.

	Payments Due by Period						
	Total	2008	2009	2010	2011	2012	Thereafter
	(In millions)						
Contractual Obligations							
Long-term debt(1)	$ 489.2	$ 4.9	$ 4.8	$ 4.8	$ 4.7	$ 4.7	$ 465.3
Operating leases(2)	10.3	4.2	3.3	1.7	0.9	0.2	
Unconditional purchase obligations(3)	568.9	25.2	25.2	52.8	51.0	48.4	366.3
Environmental liabilities(4)	9.0	2.8	0.7	1.6	0.3	0.3	3.3
Funded letter of credit fees(5)	11.2	4.5	4.5	2.2			
Interest payments(6)	217.8	39.4	38.9	38.6	38.2	37.9	24.8
Total	$ 1,306.4	$ 81.0	$ 77.4	$ 101.7	$ 95.1	$ 91.5	$ 859.7
Other Commercial Commitments							
Standby letters of credit(7)	$ 39.4	$ 39.4	$	$	$	$	$

(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 December 31, 2007, $489.2 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 Sate of Kansas Voluntary Cleaning and 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 December 31, 2007 and assume contractual amortization payments.

(7) Standby letters of credit include $5.8 million of letters of credit issued in connection with environmental liabilities, $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.

In addition to the amounts described in the above table, we owe J. Aron approximately $123.7 million plus accrued interest which will be due August 31, 2008.

Our ability to make payments on and to refinance our indebtedness, to repay the amounts owed to J. Aron, 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. Our ability to refinance our indebtedness is also subject to the availability of the credit markets, which in recent periods have been extremely volatile. 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. 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 June 2006, the Financial Accounting Standards Board (FASB), ratified its consensus on the Emerging Issues Task Force (EITF) Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement.* EITF 06-3 includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include sales, use, value added, and some excise taxes. These taxes should be presented on either a gross or net basis, and if reported on a gross basis, a company should disclose amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented. The guidance in EITF 06-3 is effective for all periods beginning after December 15, 2006 and did not have a material impact on our financial position or results of operations.

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*, by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. If a tax position is more likely than not to be sustained upon examination, then an enterprise would be required to recognize in its financial statements the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures and transition. The application of FIN No. 48 is effective for fiscal years beginning after December 15, 2006 and it did not have a material impact on our financial position or results of operations.

In September 2006, the 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 No. 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 statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are currently evaluating the effect that this statement will have on our financial statements.

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 157 and SFAS No. 107, *Disclosures about Fair Value* *of Financial Instruments*. SFAS 159 is effective for fiscal years beginning after November 15, 2007, and early adoption is permitted as of January 1, 2007, provided that the entity makes that choice in the first quarter of 2007 and also elects to apply the provisions of SFAS 157. We are currently evaluating the potential impact that SFAS 159 will have on our financial condition, results of operations and cash flows.

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 noncontrolling 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 will be required to adopt this statement as of January 1, 2009. The impact of adopting SFAS 141R 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, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling 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 us beginning January 1, 2009. We are currently evaluating the potential impact of the adoption of SFAS 160 on our consolidated financial statements.

Critical Accounting Policies

We prepare our consolidated financial statements in accordance with U.S. 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 included elsewhere in this Report. Our critical accounting policies, which are described below, could materially affect the amounts recorded in our financial statements.

Impairment of Long-Lived Assets

During 2001, Farmland accounted for long-lived assets in accordance with SFAS No. 121, *Accounting for Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.* SFAS 121 was superseded by SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which was adopted by Farmland effective January 1, 2002.

In accordance with both SFAS 144 and SFAS 121, Farmland reviewed its long-lived assets for impairment whenever events or changes in circumstances indicated 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 exceeded its estimated future undiscounted net cash flows, an impairment charge was recognized by the amount by which the carrying amount of the assets exceeded the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying value or fair value less cost to sell, and are no longer depreciated.

In its Plan of Reorganization, Farmland stated, among other things, its intent to dispose of its petroleum and nitrogen fertilizer assets. Despite this stated intent, these assets were not classified as held for sale under SFAS 144 until

October 7, 2003 because, ultimately, any disposition must be approved by the bankruptcy court and the bankruptcy court did not approve such disposition until that date. Since Farmland determined that it was more likely than not that its assets would be disposed of, those assets were tested for impairment in 2002 pursuant to SFAS 144, using projected undiscounted net cash flows. Based on Farmland s best assumptions regarding the use and eventual disposition of those assets, primarily from indications of value received from potential bidders in the bankruptcy sales process, the assets were determined to exceed the fair value expected to be received on disposition by approximately $375.1 million. Accordingly, an impairment charge was recognized for that amount in 2002. The ultimate proceeds from disposition of these assets were decided in a bidding and auction process conducted in the bankruptcy proceedings. In 2003, as a result of receiving a bid from Coffeyville Resources, LLC, Farmland revised its estimate of the amount to be generated from the disposition of these assets and an additional impairment charge of $9.6 million was taken in the year ended December 31, 2003.

As of December 31, 2007, net property, plant and equipment totaled $1,192.2 million. To the extent events or circumstances change indicating the carrying amounts of our assets may not be recoverable, we could experience asset impairments in the future.

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 gains (losses) from derivative instruments of ($323.7) million, $94.5 million and $(282.0) million in gain (loss) on derivatives for the fiscal years ended December 31, 2005, 2006 and 2007, respectively.

As of December 31, 2007, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $42.3 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 December 31, 2007 totaled $7.6 million, including $2.8 million included in current liabilities. Additionally, at December 31, 2007, $3.4 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.

Share-Based Compensation

We estimated fair value of units for all applicable periods as described below.

At March 3, 2004, we determined the per unit value of the Original Predecessor common units by assessing the fair value of the preference components associated with the preferred units based on expected future cash flows of the business and subtracting that value from the total fair value of our equity to arrive at a fair value of the residual interests of the preferred and common units.

In addition to voting rights, the holders of the preferred units, who contributed all the cash into the Original Predecessor on the acquisition date, were entitled to a return of their contributed capital plus a 15% per annum preferred yield on any outstanding unreturned contributed capital. In determining the value that the preferred unitholders transferred to the common unitholders, rather than applying a waterfall method which would have resulted in no value, we applied a discounted cash flow analysis based on a range of potential earnings outcomes and assumptions. The percent of equity value transferred from the preferred unitholders to the common unitholders was based on the discounted cash flow analysis after giving effect to the preference obligations, including the 15% per annum preferred yield. Changes in assumptions such as discount rates, prices or operating plant operating conditions used to determine the forecasted cash flows used in the valuation could have a material impact on the percent of equity value allocated to the common units. In preparing the discounted cash flow analysis, the product sales price assumptions used for the fertilizer and refinery products assumed sustained prices for a five-year period at historically high levels.

In connection with its refinancing on May 10, 2004, we obtained independent third party appraisals for the refinery and the nitrogen fertilizer plant property, plant and equipment. Taking into account the third party appraisals, we calculated an equity value for the business. The appraisals included market approach valuations and income approach valuations in the form of a discounted cash flow. The discounted cash flow analysis included assumptions for product sales prices consistent with readily available forward market indicators and reflected existing plant performance measures. Changes in assumptions such as discount rates, prices or operating plant operating conditions used to determine the forecasted cash flows used in the valuation could have a material impact on the equity value. Given the refinancing allowed us to settle the preference obligations, the equity value resulting from the appraisal was allocated pro rata to all unitholders for the 74,852,941 shares outstanding subject to a discount of 8% attributed to the common units for the non-voting status.

For the 233-day period ended December 31, 2005 and the years ended December 31, 2006 and 2007, we account for share-based compensation in accordance with SFAS No. 123(R), *Share-Based Payment*. SFAS 123(R) requires that compensation costs relating to share-based payment transactions be recognized in a company s financial statements. SFAS 123(R) applies to transactions in which an entity exchanges its equity instruments for goods or services and also may apply to liabilities an entity incurs for goods or services that are based on the fair value of those equity instruments.

In accordance with SFAS 123(R), we apply a fair-value-based measurement method in accounting for share-based override units and phantom points. Override units are equity classified awards measured using the grant date fair value with compensation expense recognized over the respective vesting period. Phantom points are liability classified awards marked to market based on their fair value at the end of each reporting period with compensation expense recognized over the respective vesting period.

At June 24, 2005 an independent third party appraisal for the refinery and the nitrogen fertilizer plant was obtained. Additionally, an independent appraisal process occurred at that time, to value the management common units that were subject to redemption and our override value units, override operating units and phantom points. The Monte Carlo method of valuation was utilized to value the override operating units, override value units and phantom points that were issued on June 24, 2005.

In addition, an independent appraisal process occurs each reporting period in order to revalue the management common units and phantom points. The significant assumptions that are used each reporting period to value the phantom and performance service points are: (1) estimated forfeiture rate; (2) explicit service period or derived service period as applicable, (3) grant-date fair value controlling basis; (4) marketability and minority interest discounts and (5) volatility.

For the independent valuations that occurred as of December 31, 2005, June 30, 2006 and September 30, 2006, a Binomial Option Pricing Model was utilized to value the phantom points. Probability-weighted values that were determined in this independent valuation process were discounted to determine the present value of the units. Prospective financial information is utilized in the valuation process. A discounted cash flow method, a variation of the income approach, and a guideline company method, which is a variation of a market approach is utilized to value the management common units.

A combination of a binomial model and a probability-weighted expected return method which utilizes the company s cash flow projections was utilized to value the additional override operating units and override value units that were issued on December 28, 2006. Additionally, this combination of a binomial model and probability-weighted expected return method was utilized to value the phantom points as of December 31, 2006, March 31, 2006 and June 30, 2007. Management believes that this method is preferable for the valuation of the override units and phantom points as it allows a better integration of the cash flows with other inputs including the timing of potential exit events that impact the estimated fair value of the override units and phantom points.

There is considerable judgment in the determination of the significant assumptions used in determining the fair value for our share based compensation. Changes in these assumptions could result in material changes in the amounts recognized as compensation expense in our consolidated financial statements. For example, if we accelerated the expected term or maturity date of the override units as a result of a change in assumptions for the timeframe for when the override units begin to receive distributions (i.e., timing of an exit event), or increased the current value of the common units based on changes in the projected future cash flows of the business, the measurement date fair value of the override units and the phantom points could materially increase, which could materially increase the amount of compensation expense recognized in our consolidated financial statements. In addition, changes in the assumptions of discount rate, volatility, or free cash flows will impact the amount of compensation expense recognized. The extent of the impact is influenced by the expected term or maturity date of the override units and current value of the common units.

Assuming the price of our common stock increases $1.00, additional compensation expense of approximately $2.2 million and $6.2 million would be recognized over the vesting period for phantom points and override units, respectively.

Purchase Price Accounting and Allocation

The Subsequent Acquisition described in Note 1 to our audited consolidated financial statements included elsewhere in this Report was accounted for using the purchase method of accounting as of June 24, 2005. The allocation of the purchase price to the net assets acquired was performed in accordance with SFAS No. 141, *Business Combinations.* In connection with the allocation of the purchase price, management used estimates and assumptions to determine the fair value of the assets acquired and liabilities assumed. Changes in these assumptions and estimates such as discount rates and future cash flows used in the appraisal process could have a material impact on how the purchase price were allocated at the date of acquisition.

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 estimable.

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 revenues, expenses, net income, assets and liabilities as such would not be included in our consolidated financial statements.

Item 7B. *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, have 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 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 than 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. Our most prevalent risk management activity is to sell forward the crack spread when opportunities exist to lock in a margin sufficient to meet our cash obligations or our operating plan. Selling forward derivative contracts for which the underlying commodity is the crack spread enables us to lock in a margin on the spread between the price of crude oil and price of refined products. 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.

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.

On December 31, 2007, we had the following open commodity derivative contracts whose unrealized gains and losses are included in gain (loss) on derivatives in the consolidated statements of operations:

Our petroleum segment holds commodity derivative contracts in the form of three swap agreements for the period from July 1, 2005 to June 30, 2010 with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and a related party of ours. The swap agreements were originally executed on June 16, 2005 in conjunction with the Subsequent Acquisition of Immediate Predecessor and required under the terms of our long-term debt agreements. These agreements were subsequently assigned from Coffeyville Acquisition LLC to Coffeyville Resources, LLC on June 24, 2005. The total notional quantities on the date of execution were 100,911,000 barrels of crude oil, 2,348,802,750 gallons of unleaded gasoline and 1,889,459,250 gallons of heating oil. Pursuant to these swaps, we receive a fixed price with respect to the heating oil and the unleaded gasoline while we pay a fixed price with respect to crude oil. In June 2006, a subsequent swap was entered into with J. Aron to effectively reduce our unleaded notional quantity and increase our heating oil notional quantity by 229,671,750 gallons over the period July 2, 2007 to June 30, 2010. Additionally, several other swaps were entered into with J. Aron to adjust effective net notional amounts of the aggregate position to better align with actual production volumes. The swap agreements were executed at the prevailing market rate at the time of execution and management believed the swap agreements would provide an economic hedge on future transactions. At December 31, 2007 the net notional open amounts under these swap agreements were 42,309,750 barrels of crude oil, 888,504,750 gallons of heating oil and 888,504,750 gallons of unleaded gasoline. The purpose of these contracts is to economically hedge 21,154,875 barrels of heating oil crack spreads, the price spread between crude oil and heating oil, and 21,154,875 barrels of unleaded gasoline crack spreads, the price spread between crude oil and unleaded gasoline. These open contracts had a total unrealized net loss at December 31, 2007 of approximately $103.2 million.

Our petroleum segment also holds various NYMEX positions through Merrill Lynch, Pierce, Fenner & Smith Incorporated. At December 31, 2007, we were short 140 heating oil contracts and 240 unleaded gasoline contracts, reflecting an unrealized loss of $1.3 million on that date.

As of December 31, 2007, a $1.00 change in quoted futures price for the crack spreads described in the first bullet point would result in a $42.3 million change to the fair value of the derivative commodity position and the same change in net income.

Interest Rate Risk

As of December 31, 2007, all of our $489.2 million of outstanding term debt was at floating rates. Although borrowings under our revolving credit facility are at floating rates based on prime, as of December 31, 2007, we had no outstanding revolving debt. An increase of 1.0% in the LIBOR rate would result in an increase in our interest expense of approximately $5.0 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
$325.0 million	6/29/07	3/30/08	4.195%
$250.0 million	3/31/08	3/30/09	4.195%
$180.0 million	3/31/09	3/30/10	4.195%
$110.0 million	3/31/10	6/29/10	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.

Item 8. ***Financial Statements and Supplementary Data***

CVR Energy, Inc. and Subsidiaries

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors
CVR Energy, Inc.:

We have audited the accompanying consolidated balance sheets of CVR Energy, Inc. and subsidiaries (the Successor) as of December 31, 2006 and 2007, and the related statements of operations, equity, and cash flows for Coffeyville Group Holdings, LLC and subsidiaries, excluding Leiber Holdings, LLC (the Predecessor) for the 174-day period ended June 23, 2005 and for the Successor, for the 233-day period ended December 31, 2005 and for the years ended December 31, 2006 and 2007, as discussed in note 1 to the consolidated financial statements. These consolidated financial statements are the responsibility of the Successor s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Successor as of December 31, 2006 and 2007, and the results of the Predecessor s operations and its cash flows for the 174-day period ended June 23, 2005 and the results of the Successor s operations and its cash flows for the 233-day period ended December 31, 2005 and for the years ended December 31, 2006 and 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in note 1 to the consolidated financial statements, effective June 24, 2005, the Successor acquired the net assets of the 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.

/s/ KPMG LLP

Kansas City, Missouri
March 28, 2008

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 41,919,260	$ 30,508,737
Accounts receivable, net of allowance for doubtful accounts of $375,443 and $390,532, respectively	69,589,161	86,545,870
Inventories	161,432,793	249,243,198
Prepaid expenses and other current assets	18,524,017	14,185,531
Insurance receivable		73,860,112
Income tax receivable	32,099,163	25,273,016
Deferred income taxes	18,888,660	78,264,910
Total current assets	342,453,054	557,881,374
Property, plant, and equipment, net of accumulated depreciation	1,007,155,873	1,192,174,459
Intangible assets, net	638,456	473,492
Goodwill	83,774,885	83,774,885
Deferred financing costs, net	9,128,258	7,514,505
Insurance receivable		11,400,000
Other long-term assets	6,328,989	2,849,376
Total assets	$ 1,449,479,515	$ 1,856,068,091
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 5,797,981	$ 4,873,706
Note payable and capital lease obligations		11,640,261
Payable to swap counterparty	36,894,802	262,414,874
Accounts payable	138,911,088	159,142,252
Personnel accruals	24,731,283	36,659,475
Accrued taxes other than income taxes	9,034,841	14,732,282
Deferred revenue	8,812,350	13,161,103
Other current liabilities	6,017,435	33,818,770
Total current liabilities	230,199,780	536,442,723
Long-term liabilities:		
Long-term debt, less current portion	769,202,019	484,328,313
Accrued environmental liabilities	5,395,105	4,844,313
Deferred income taxes	284,122,958	286,985,797
Other long-term liabilities		1,121,722

Payable to swap counterparty	72,806,486	88,230,110
Total long-term liabilities	1,131,526,568	865,510,255
Commitments and contingencies		
Minority interest in subsidiaries	4,326,188	10,600,000
Management voting common units subject to redemption, 201,063 units issued and outstanding in 2006	6,980,907	
Stockholders equity/members equity		
Voting common units, 22,614,937 units issued and outstanding in 2006	73,593,326	
Management nonvoting override units, 2,976,353 units issued and outstanding in 2006	2,852,746	
Common Stock $0.01 par value per share, 350,000,000 shares authorized; 86,141,291 shares issued and outstanding		861,413
Additional paid-in-capital		460,550,842
Retained deficit		(17,897,142)
Total stockholders equity/members equity	76,446,072	443,515,113
Total liabilities and stockholders equity/members equity	$ 1,449,479,515	$ 1,856,068,091

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

	Immediate Predecesssor 174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Successor Year Ended December 31, 2006	Year Ended December 31, 2007
Net sales	$ 980,706,261	$ 1,454,259,542	$ 3,037,567,362	$ 2,966,864,453
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	768,067,178	1,168,137,217	2,443,374,743	2,291,069,011
Direct operating expenses (exclusive of depreciation and amortization)	80,913,862	85,313,202	198,979,983	276,136,830
Selling, general and administrative expenses (exclusive of depreciation and amortization)	18,341,522	18,320,030	62,600,121	93,121,755
Net costs associated with flood				41,523,266
Depreciation and amortization	1,128,005	23,954,031	51,004,582	60,779,175
Total operating costs and expenses	868,450,567	1,295,724,480	2,755,959,429	2,762,630,037
Operating income	112,255,694	158,535,062	281,607,933	204,234,416
Other income (expense):				
Interest expense and other financing costs	(7,801,821)	(25,007,159)	(43,879,644)	(61,126,183)
Interest income	511,687	972,264	3,450,190	1,099,571
Gain (loss) on derivatives	(7,664,725)	(316,062,111)	94,493,141	(281,978,095)
Loss on extinguishment of debt	(8,093,754)		(23,360,306)	(1,257,764)
Other income (expense)	(762,616)	(563,190)	(899,831)	355,808
Total other income (expense)	(23,811,229)	(340,660,196)	29,803,550	(342,906,663)
Income (loss) before income taxes and minority interest in subsidiaries	88,444,465	(182,125,134)	311,411,483	(138,672,247)
Income tax expense (benefit)	36,047,516	(62,968,044)	119,840,160	(81,638,610)
				210,062

Minority interest in loss of subsidiaries								
Net income (loss)	$	52,396,949	$	(119,157,090)	$	191,571,323	$	(56,823,575)
Unaudited Pro Forma Information (Note 12)								
Net earnings (loss) per share								
Basic					$	2.22	$	(0.66)
Diluted					$	2.22	$	(0.66)
Weighted average common shares outstanding:								
Basic						86,141,291		86,141,291
Diluted						86,158,791		86,141,291

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY/MEMBERS EQUITY

	Voting Preferred	Nonvoting Common	Unearned Compensation	Total
Immediate Predecessor				
Members Equity, December 31, 2004	$ 10,485,160	$ 7,584,993	$ (3,985,991)	$ 14,084,162
Recognition of earned compensation expense related to common units			3,985,991	3,985,991
Contributed capital	728,724			728,724
Dividends on preferred units ($0.70 per unit)	(44,083,323)			(44,083,323)
Dividends to management on common units ($0.70 per unit)		(8,128,170)		(8,128,170)
Net income	44,239,908	8,157,041		52,396,949
Members Equity, June 23, 2005	$ 11,370,469	$ 7,613,864	$	$ 18,984,333

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY/MEMBERS EQUITY

	Management Voting Common Units Subject to Redemption		Note Receivable from Management Unit Holder	Total
	Units	Dollars	Dollars	Dollars
Successor				
For the 233 days ended December 31, 2005, and the year ended December 31, 2006				
Balance at May 13, 2005		$	$	$
Issuance of 177,500 common units for cash	177,500	1,775,000		1,775,000
Issuance of 50,000 common units for note receivable	50,000	500,000	(500,000)	
Adjustment to fair value for management common units		3,035,586		3,035,586
Net loss allocated to management common units		(1,138,236)		(1,138,236)
Balance at December 31, 2005	227,500	4,172,350	(500,000)	3,672,350
Payment of note receivable			150,000	150,000
Forgiveness of note receivable			350,000	350,000
Adjustment to fair value for management common units		4,239,548		4,239,548
Prorata reduction of management common units outstanding	(26,437)			
Distributions to management on common units		(3,119,188)		(3,119,188)
Net income allocated to management common units		1,688,197		1,688,197
Balance at December 31, 2006	201,063	6,980,907		6,980,907
Adjustment to fair value for management common units		2,017,889		2,017,889
Net loss allocated to management common units		(343,034)		(343,034)
Change from partnership to corporate reporting structure	(201,063)	(8,655,762)		(8,655,762)
Balance at December 31, 2007		$	$	$

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY/MEMBERS EQUITY (Continued)

	Voting Common Units		Management Nonvoting Override Operating Units		Management Nonvoting Override Value Units		Total
	Units	Dollars	Units	Dollars	Units	Dollars	Dollars
For the 233 days ended December 31, 2005, and the year ended December 31, 2006							
Balance at May 13, 2005		$		$		$	$
Issuance of 23,588,500 common units for cash	23,588,500	235,885,000					235,885,000
Issuance of 919,630 nonvested operating override units			919,630				
Issuance of 1,839,265 nonvested value override units					1,839,265		
Recognition of share-based compensation expense related to override units				602,381		395,187	997,568
Adjustment to fair value for management common units		(3,035,586)					(3,035,586)
Net loss allocated to common units		(118,018,854)					(118,018,854)

Balance at December 31, 2005	23,588,500	114,830,560	919,630	602,381	1,839,265	395,187	115,828,128
Issuance of 2,000,000 common units for cash	2,000,000	20,000,000					20,000,000
Recognition of share-based compensation expense related to override units				1,160,530		694,648	1,855,178
Adjustment to fair value for management common units		(4,239,548)					(4,239,548)
Prorata reduction of common units outstanding	(2,973,563)						
Issuance of 72,492 nonvested operating override units			72,492				
Issuance of 144,966 nonvested value override units					144,966		
Distributions to common unit holders		(246,880,812)					(246,880,812)
Net income allocated to common units		189,883,126					189,883,126
Balance at December 31, 2006	22,614,937	73,593,326	992,122	1,762,911	1,984,231	1,089,835	76,446,072
Recognition of share-based compensation expense related to override units				1,017,157		700,771	1,717,928
Adjustment to fair value for management		(2,017,889)					(2,017,889)

common units							
Adjustment to fair value for minority interest		(1,053,248)					(1,053,248)
Reversal of minority interest fair value adjustments upon redemption of the minority interest		1,053,248					1,053,248
Net loss allocated to common units		(38,583,399)					(38,583,399)
Change from partnership to corporate reporting structure	(22,614,937)	(32,992,038)	(992,122)	(2,780,068)	(1,984,231)	(1,790,606)	(37,562,712)
Balance at December 31, 2007		$		$		$	$

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY/MEMBERS EQUITY (Continued)

	Common Stock Shares Issued	Common Stock Amount	Additional Paid-In Capital	Retained Deficit	Total
Balance at January 1, 2007		$	$	$	$
Change from partnership to corporate reporting structure	62,866,720	628,667	45,589,807		46,218,474
Issuance of common stock in exchange for minority interest of related party	247,471	2,475	4,699,474		4,701,949
Cash dividend declared			(10,600,000)		(10,600,000)
Public offering of common stock, net of stock issuance costs of $39,873,655	22,917,300	229,173	395,325,872		395,555,045
Purchase of common stock by employees through share purchase program	82,700	827	1,570,473		1,571,300
Share-based compensation			23,399,639		23,399,639
Issuance of common stock to employees	27,100	271	565,577		565,848
Net loss				(17,897,142)	(17,897,142)
Balance at December 31, 2007	86,141,291	$ 861,413	$ 460,550,842	$ (17,897,142)	$ 443,515,113

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS

	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
Cash flows from operating activities:				
Net income (loss)	$ 52,396,949	$ (119,157,090)	$ 191,571,323	$ (56,823,575)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization	1,128,005	23,954,031	51,004,582	68,406,248
Provision for doubtful accounts	(190,468)	275,189	100,255	15,089
Amortization of deferred financing costs	812,166	1,751,041	3,336,795	2,777,504
Loss on disposition of fixed assets			1,188,360	1,272,375
Loss on extinguishment of debt	8,093,754		23,360,306	1,257,764
Forgiveness of note receivable			350,000	
Share-based compensation	3,985,991	1,092,587	16,903,737	44,082,919
Minority interest in loss of subsidiaries				(210,062)
Changes in assets and liabilities, net of effect of acquisition:				
Accounts receivable	(11,334,177)	(34,506,244)	1,870,636	(16,971,798)
Inventories	(59,045,550)	1,895,473	(7,156,975)	(79,568,448)
Prepaid expenses and other current assets	(937,543)	(6,491,633)	(5,383,117)	4,848,136
Insurance receivable				(105,260,092)
Insurance proceeds for flood				19,999,980
Other long-term assets	3,036,659	(4,651,733)	1,971,859	3,245,963
Accounts payable	16,124,794	40,655,763	5,004,826	36,028,071
Accrued income taxes	4,503,574	(136,398)	(37,038,777)	6,826,147
Deferred revenue	(9,073,050)	9,983,132	(3,217,637)	4,348,753
Other current liabilities	1,254,196	10,404,693	4,591,121	27,027,465
Payable to swap counterparty		256,722,289	(147,021,001)	240,943,696
Accrued environmental liabilities	(1,553,184)	(538,365)	(1,614,283)	(550,792)
Other long-term liabilities	(297,105)	(295,776)		1,121,722
Deferred income taxes	3,803,937	(98,424,817)	86,770,299	(56,901,929)
Net cash provided by operating activities	12,708,948	82,532,142	186,592,309	145,915,136
Cash flows from investing activities:				

Cash paid for acquisition of Immediate Predecessor, net of cash acquired		(685,125,669)		
Capital expenditures	(12,256,793)	(45,172,134)	(240,225,392)	(268,592,539)
Net cash used in investing activities	(12,256,793)	(730,297,803)	(240,225,392)	(268,592,539)
Cash flows from financing activities:				
Revolving debt payments	(343,449)	(69,286,016)	(900,000)	(345,800,000)
Revolving debt borrowings	492,308	69,286,016	900,000	345,800,000
Proceeds from issuance of long-term debt		500,000,000	805,000,000	50,000,000
Principal payments on long-term debt	(375,000)	(562,500)	(529,437,500)	(335,797,981)
Payment of financing costs		(24,628,315)	(9,363,681)	(2,491,327)
Prepayment penalty on extinguishment of debt			(5,500,000)	
Payment of note receivable			150,000	
Issuance of members equity		237,660,000	20,000,000	
Net proceeds from sale of common stock				399,556,188
Distribution of members equity	(52,211,493)		(250,000,000)	(10,600,000)
Sale of managing general partnership interest				10,600,000
Net cash provided by (used in) financing activities	(52,437,634)	712,469,185	30,848,819	111,266,880
Net increase (decrease) in cash and cash equivalents	(51,985,479)	64,703,524	(22,784,264)	(11,410,523)
Cash and cash equivalents, beginning of period	52,651,952		64,703,524	41,919,260
Cash and cash equivalents, end of period	$ 666,473	$ 64,703,524	$ 41,919,260	$ 30,508,737
Supplemental disclosures				
Cash paid for income taxes, net of refunds (received)	$ 27,040,000	$ 35,593,172	$ 70,108,638	$ (31,562,828)
Cash paid for interest	$ 7,287,351	$ 23,578,178	$ 51,854,047	$ 56,886,131
Non-cash investing and financing activities:				
Step-up in basis in property for exchange of common stock for minority interest, net of deferred taxes of $388,518	$	$	$	$ 585,822
Accrual of construction in progress additions	$	$	$ 45,991,429	$ (15,268,284)
Contributed capital through Leiber tax savings	$ 728,724	$	$	$
Notes payable and capital lease obligations for insurance and inventory	$	$	$	$ 11,640,261

See accompanying notes to consolidated financial statements.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and History of the Company

Organization

The Company or CVR may be used to refer to CVR Energy, Inc. and, unless the context otherwise requires, its subsidiaries. Any references to the Company as of a date prior to October 16, 2007 (the date of the restructuring as further discussed in this note) and subsequent to June 24, 2005 are to Coffeyville Acquisition LLC (CALLC) and its subsidiaries.

On June 24, 2005, CALLC acquired all of the outstanding stock of Coffeyville Refining & Marketing, Inc. (CRM); Coffeyville Nitrogen Fertilizers, Inc. (CNF); Coffeyville Crude Transportation, Inc. (CCT); Coffeyville Pipeline, Inc. (CP); and Coffeyville Terminal, Inc. (CT) (collectively, CRIncs). CRIncs collectively own 100% of CL JV Holdings, LLC (CLJV) and, directly or through CLJV, they collectively own 100% of Coffeyville Resources, LLC (CRLLC) and its wholly owned subsidiaries, Coffeyville Resources Refining & Marketing, LLC (CRRM); Coffeyville Resources Nitrogen Fertilizers, LLC (CRNF); Coffeyville Resources Crude Transportation, LLC (CRCT); Coffeyville Resources Pipeline, LLC (CRP); and Coffeyville Resources Terminal, LLC (CRT).

The Company, through its wholly-owned subsidiaries, acts as an independent petroleum refiner and marketer in the mid-continental United States and a producer and marketer of upgraded nitrogen fertilizer products in North America. The Company s operations include two business segments: the petroleum segment and the nitrogen fertilizer segment.

CALLC formed CVR Energy, Inc. as a wholly owned subsidiary, incorporated in Delaware in September 2006, in order to effect an initial public offering. CALLC formed Coffeyville Refining & Marketing Holdings, Inc. (Refining Holdco) as a wholly owned subsidiary, incorporated in Delaware in August 2007, by contributing its shares of CRM to Refining Holdco in exchange for its shares. Refining Holdco was formed in connection with a financing transaction in August 2007. The initial public offering of CVR was consummated on October 26, 2007. In conjunction with the initial public offering, a restructuring occurred in which CVR became a direct or indirect owner of all of the subsidiaries of CALLC. Additionally, in connection with the initial public offering, CALLC was split into two entities: Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC (CALLC II).

Initial Public Offering of CVR Energy, Inc.

On October 26, 2007, CVR Energy, Inc. completed an initial public offering of 23,000,000 shares of its common stock. The initial public offering price was $19.00 per share.

The net proceeds to CVR from the initial public offering were approximately $408.5 million, after deducting underwriting discounts and commissions, but before deduction of offering expenses. The Company also incurred approximately $11.4 million of other costs related to the initial public offering. The net proceeds from this offering were used to repay $280 million of term debt under the Company s credit facility and to repay all indebtedness under the Company s $25 million unsecured facility and $25 million secured facility, including related accrued interest through the date of repayment of approximately $5.9 million. Additionally, $50 million of net proceeds were used to repay outstanding indebtedness under the revolving loan facility under the Company s credit facility. In connection with the repayment of the $25 million unsecured facility and the $25 million secured facility, the Company recorded a write-off of unamortized deferred financing fees of approximately $1.3 million in the fourth quarter of 2007.

In connection with the initial public offering, CVR became the indirect owner of the subsidiaries of CALLC and CALLC II. This was accomplished by CVR issuing 62,866,720 shares of its common stock to CALLC and CALLC II, its majority stockholders, in conjunction with the mergers of two newly formed direct subsidiaries of CVR into Refining Holdco and CNF. Concurrent with the merger of the subsidiaries and in

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

accordance with a previously executed agreement, the Company s chief executive officer received 247,471 shares of CVR common stock in exchange for shares that he owned of Refining Holdco and CNF. The shares were fully vested and were exchanged at fair market value.

The Company also issued 27,100 shares of common stock to its employees on October 24, 2007 in connection with the initial public offering. The compensation expense recorded in the fourth quarter of 2007 was $565,848 related to shares issued. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, which does not include the non-vested shares issued noted below.

On October 24, 2007, 17,500 shares of non-vested stock having a fair value of $365,400 at the date of grant were issued to outside directors. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have dividend and voting rights on these shares from the date of grant. The fair value of each share of restricted stock was measured based on the market price of the common stock as of the date of grant and will be amortized over the respective vesting periods. One-third of the restricted stock will vest on October 24, 2008, one-third will vest on October 24, 2009, and the final one-third will vest on October 24, 2010. Additionally, options to purchase 10,300 common shares at an exercise price of $19.00 per share were granted to outside directors on October 22, 2007. These awards will vest over a three year service period. Fair value was measured using an option-pricing model at the date of grant.

Nitrogen Fertilizer Limited Partnership

In conjunction with the consummation of CVR s initial public offering, CVR transferred CRNF, its nitrogen fertilizer business, to a newly created limited partnership (Partnership) in exchange for a managing general partner interest (managing GP interest), a special general partner interest (special GP interest, represented by special GP units) and a de minimis limited partner interest (LP interest, represented by special LP units). This transfer was not considered a business combination as it was a transfer of assets among entities under common control and, accordingly, balances were transferred at their historical cost. CVR concurrently sold the managing GP interest to an entity owned by its controlling stockholders and senior management at fair market value. The board of directors of CVR determined, after consultation with management, that the fair market value of the managing general partner interest was $10.6 million. This interest has been reflected as minority interest in the consolidated balance sheet at December 31, 2007.

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 determine the Partnership s raw material costs and output revenues. Other business expenses of the Partnership were 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 flows due 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 expectations of the Partnership s operations, including production volumes and operating costs, which were developed by management based on historical operations and experience. Price projections were based on information received from Blue, Johnson & Associates, a leading fertilizer industry consultant in the United States which CVR routinely uses for fertilizer market analysis.

In conjunction with CVR Energy s indirect ownership of the special GP interest, it initially owned all of the interests in the Partnership (other than the managing general partner interest and the IDRs) and initially was entitled to all cash distributed by the Partnership. The managing general partner is not entitled to participate in Partnership distributions except with respect to its IDRs, which entitle the managing general partner to receive increasing percentages (up to 48%) of the cash the Partnership distributes in excess of $0.4313 per unit in a quarter. However, the Partnership is not permitted to make any distributions with respect

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to the IDRs until the aggregate Adjusted Operating Surplus, as defined in the amended and restated partnership agreement, generated by the Partnership during the period from the completion of the Partnership s initial public offering of its common units representing limited partner interests (Partnership Offering) through December 31, 2009 has been distributed in respect of the GP units and subordinated GP units, which CVR Energy will indirectly hold following completion of the Partnership Offering, and the Partnership s common units (which will be issued in connection with the Partnership Offering) and any other partnership interests that are issued in the future. The Partnership and its subsidiaries are currently guarantors under CRLLC s credit facility.

The Partnership is operated by CVR s senior management pursuant to a services agreement among CVR, the managing general partner, and the Partnership. The Partnership is managed by the managing general partner and, to the extent described below, CVR, as special general partner. As special general partner of the Partnership, CVR has joint management rights regarding the appointment, termination, and compensation of the chief executive officer and chief financial officer of the managing general partner, has the right to designate two members of the board of directors of the managing general partner, and has joint management rights regarding specified major business decisions relating to the Partnership. CVR the Partnership and the managing general partner also entered into a number of agreements to regulate certain business relations between the partners.

At December 31, 2007, the Partnership had 30,333 special LP units outstanding, representing 0.1% of the total Partnership units outstanding, and 30,303,000 special GP interests outstanding, representing 99.9% of the total Partnership units outstanding. In addition, the managing general partner owned the managing general partner interest and the IDRs. The managing general partner contributed 1% of CRNF s interest to the Partnership in exchange for its managing general partner interest and the IDRs.

On February 28, 2008, the Partnership filed a registration statement with the SEC to effect the contemplated initial public offering of its common units representing limited partner interests. The registration statement provided that upon consummation of the Partnership s initial public offering, CVR will indirectly own the Partnership s special general partner and approximately 87% of the outstanding units of the Partnership. There can be no assurance that any such offering will be consummated on the terms described in the registration statement or at all. The offering is under review by the Securities and Exchange Commission (SEC) and as a result the terms and resulting structure disclosed below could be materially different.

In connection with the Partnership s initial public offering, CRLLC will contribute all of its special LP units to the Partnership s special general partner and all of the Partnership s special general partner interests and special limited partner interests will be converted into a combination of GP and subordinated GP units. Following the initial public offering, the Partnership will have five types of partnership interest outstanding:

- 5,250,000 common units representing limited partner interests, all of which the Partnership will sell in the initial public offering;
- 18,750,000 GP units representing special general partner interests, all of which will be held by the Partnership s special general partner;
- 18,000,000 subordinated GP units representing special general partner interests, all of which will be held by the Partnership s special general partner;

incentive distribution rights representing limited partner interests, all of which will be held by the Partnership s managing general partner; and

a managing general partner interest, which is not entitled to any distributions, which is held by the Partnership s managing general partner.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effective with the Partnerships initial public offering, the partnership agreement will require that the Partnership distribute all of its cash on hand at the end of each quarter, less reserves established by its managing general partner, subject to the sustainability requirement in the event the Partnership elects to increase the quarterly distribution amount. The amount of available cash may be greater or less than the aggregate amount necessary to make the minimum quarterly distribution on all common units, GP units and subordinated units.

Subsequent to the initial public offering, the Partnership will make minimum quarterly distributions of $0.375 per common unit ($1.50 per common unit on an annualized basis) to the extent the Partnership has sufficient available cash. In general, cash distributions will be made each quarter as follows:

First, to the holders of common units and GP units until each common unit and GP unit has received a minimum quarterly distribution of $0.375 plus any arrearages from prior quarters;

Second, to the holders of subordinated units, until each subordinated unit has received a minimum quarterly distribution of $0.375; and

Third, to all unitholders, pro rata, until each unit has received a quarterly distribution of $0.4313.

If cash distributions exceed $0.4313 per unit in a quarter, the Partnership s managing general partner, as holder of the IDRs, will receive increasing percentages, up to 48%, of the cash the Partnership distributes in excess of $0.4313 per unit. However, the managing general partner will not be entitled to receive any distributions in respect of the IDRs until the Partnership has made cash distributions in an aggregate amount equal to the Partnership s adjusted operating surplus generated during the period from the closing of the initial public offering until December 31, 2009.

During the subordination period, the subordinated units will not be entitled to receive any distributions until the common units and GP units have received the minimum quarterly distribution of $0.375 per unit plus any arrearages from prior quarters. The subordination period will end once the Partnership meets the financial tests in the partnership agreement.

If the Partnership meets the financial tests in the partnership agreement for any three consecutive four-quarter periods ending on or after the first quarter whose first day begins at least three years following the closing of the Partnership Offering, 25% of the subordinated GP units will convert into GP units on a one-for-one basis. If the Partnership meets these financial tests for any three consecutive four-quarter periods ending on or after the first quarter whose first day begins at least four years following the closing of the Partnership Offering, an additional 25% of the subordinated GP units will convert into GP units on a one-for-one basis. The early conversion of the second 25% of the subordinated GP units may not occur until at least one year following the end of the last four-quarter period in respect of which the first 25% of the subordinated GP units were converted. If the subordinated GP units have converted into subordinated LP units at the time the financial tests are met they will convert into common units, rather than GP units. In addition, the subordination period will end if the managing general partner is removed as the managing general partner where cause (as defined in the partnership agreement) does not exist and no units held by the managing general partner and its affiliates are voted in favor of that removal.

When the subordination period ends, all subordinated units will convert into GP units or common units on a one-for-one basis, and the common units and GP units will no longer be entitled to arrearages.

The partnership agreement authorizes the Partnership to issue an unlimited number of additional units and rights to buy units for the consideration and on the terms and conditions determined by the managing general partner without the approval of the unitholders.

The Partnership will distribute all cash received by it or its subsidiaries in respect of accounts receivable existing as of the closing of the initial public offering exclusively to its special general partner.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The managing general partner, together with the special general partner, manages and operates the Partnership. Common unitholders will only have limited voting rights on matters affecting the Partnership. In addition, common unitholders will have no right to elect either of the general partners or the managing general partner s directors on an annual or other continuing basis.

If at any time the managing general partner and its affiliates own more than 80% of the common units, the managing general partner will have the right, but not the obligation, to purchase all of the remaining common units at a purchase price equal to the greater of (x) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (y) the highest per-unit price paid by the managing general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed.

Successor and Immediate Predecessor

Successor refers collectively to both CVR Energy, Inc. and CALLC. CALLC was formed as a Delaware limited liability company on May 13, 2005. On June 24, 2005, CALLC acquired all of the outstanding stock of CRIncs from Coffeyville Group Holdings, LLC (Immediate Predecessor) (the Subsequent Acquisition). As a result of this transaction, CRIncs ownership increased to 100% of CLJV, a Delaware limited liability company formed on September 27, 2004. CRIncs directly and indirectly, through CLJV, collectively own 100% of CRLLC and its wholly owned subsidiaries, CRRM; CRNF; CRCT; CRP; and CRT.

CALLC 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 (see notes 15 and 16) 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 gain (loss) on derivatives for the 233 days ended December 31, 2005.

Immediate Predecessor was a Delaware limited liability company formed in October 2003. There was no financial statement activity until March 3, 2004, when Immediate Predecessor, acting through wholly owned subsidiaries, acquired the assets of the former Farmland Industries, Inc. (Farmland) Petroleum Division and one facility located in Coffeyville, Kansas within Farmland s eight-plant Nitrogen Fertilizer Manufacturing and Marketing Division (collectively, Original Predecessor) (the Initial Acquisition). As of March 3, 2004, Immediate Predecessor owned 100% of CRIncs, and CRIncs owned 100% of CRLLC and its wholly owned subsidiaries, CRRM, CRNF, CRCT, CRP, and CRT. Farmland was a farm supply cooperative and a processing and marketing cooperative.

Since the assets and liabilities of Successor and Immediate Predecessor (collectively, CVR) were each presented on a new basis of accounting, the financial information for Successor and Immediate Predecessor, is not comparable.

On October 8, 2004, Immediate Predecessor, acting through its wholly owned subsidiaries, CRM and CNF, contributed 68.7% of its membership in CRLLC to CLJV, in exchange for a controlling interest in CLJV. Concurrently, The Leiber Group, Inc., a company whose majority stockholder was Pegasus Partners II, L.P., the Immediate Predecessor s principal stockholder, contributed to CLJV its interest in the Judith Leiber business, a designer handbag business, in exchange for a minority interest in CLJV. The Judith Leiber business was at the time owned through Leiber Holdings, LLC (LH), a Delaware limited liability company wholly owned at the time by CLJV.

Based on the relative values of the properties at the time of contribution to CLJV, CRM and CNF collectively, were entitled to 80.5% of CLJV s net profits and net losses. Under the terms of CRLLC s credit agreement, CRLLC was permitted to make tax distributions to its members, including CLJV, in amounts equal to the tax liability that would be incurred by CRLLC if its net income were subject to corporate-level income tax. From the tax distributions CLJV received from CRLLC as of December 31, 2004 and June 23, 2005, CLJV contributed $1,600,000 and $4,050,000, respectively, to LH which is presented as

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

tax expense in the respective periods in the accompanying consolidated statements of operations for the reasons discussed below.

On June 23, 2005, as part of the stock purchase agreement, LH completed a merger with Leiber Merger, LLC, a wholly owned subsidiary of The Leiber Group, Inc. As a result of the merger, the surviving entity was LH. Under the terms of the agreement, CLJV forfeited all of its ownership in LH to The Leiber Group, Inc in exchange for LH s interest in CLJV. The result of this transaction was to effectively redistribute the contributed businesses back to The Leiber Group, Inc.

The operations of LH and its subsidiaries (collectively, Leiber) have not been included in the accompanying consolidated financial statements of the Predecessor because Leiber s operations were unrelated to, and are not part of, the ongoing operations of CVR. CLJV s management was not the same as the Immediate Predecessor s, the Successor s, or CVR s, there were no intercompany transactions between CLJV and the Immediate Predecessor, the Successor, or CVR, aside from the contributions, and the Immediate Predecessor only participated in the joint venture for a short period of time. The tax benefits received from LH, as a result of losses incurred by LH, have been reflected as capital contributions in the accompanying consolidated financial statements of the Immediate Predecessor.

Successor Acquisition

On May 15, 2005, Successor and Immediate Predecessor entered into an agreement whereby Successor acquired 100% of the outstanding stock of CRIncs with an effective date of June 24, 2005 for $673,273,440, including the assumption of $353,084,637 of liabilities. Successor also paid transaction costs of $12,518,702, which consisted of legal, accounting, and advisory fees of $5,782,740 paid to various parties, and transaction fees of $6,000,000 and $735,962 in expenses related to the acquisition paid to institutional investors (see note 16). Successor s primary reason for the purchase was the belief that long-term fundamentals for the refining industry were strengthening and the capital requirement was within its desired investment range. The cost of the Subsequent Acquisition was financed through long-term borrowings of approximately $500 million, short-term borrowings of approximately $12.6 million, and the issuance of common units for approximately $227.7 million. The allocation of the purchase price at June 24, 2005, the date of the Subsequent Acquisition, is as follows:

Assets acquired		
Cash	$	666,473
Accounts receivable		37,328,997
Inventories		156,171,291
Prepaid expenses and other current assets		4,865,241
Intangibles, contractual agreements		1,322,000
Goodwill		83,774,885
Other long-term assets		3,837,647
Property, plant, and equipment		750,910,245
Total assets acquired	$	1,038,876,779
Liabilities assumed		

Accounts payable	$	47,259,070
Other current liabilities		16,017,210
Current income taxes		5,076,012
Deferred income taxes		276,888,816
Other long-term liabilities		7,843,529
Total liabilities assumed	$	353,084,637
Cash paid for acquisition of Immediate Predecessor	$	685,792,142

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying CVR consolidated financial statements include the accounts of CVR Energy, Inc. and its majority-owned direct and indirect subsidiaries. The ownership interest of minority investors in its subsidiaries are recorded as minority interest. All intercompany accounts and transactions have been eliminated in consolidation.

Cash and Cash Equivalents

For purposes of the consolidated statements of cash flows, CVR considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents. In connection with CVR s initial public offering, $4.2 million of deferred offering costs in 2007 were presented in operating activities in the interim financial statements. Such amounts have now been reflected as financing activities for the 2007 period in the Consolidated Statements of Cash Flows. The impact on prior financial statements of this revision is not considered material.

Accounts Receivable

CVR grants credit to its customers. Credit is extended based on an evaluation of a customer s financial condition; generally, collateral is not required. Accounts receivable are due on negotiated terms and are stated at amounts due from customers, net of an allowance for doubtful accounts. Accounts outstanding longer than their contractual payment terms are considered past due. CVR determines its allowance for doubtful accounts by considering a number of factors, including the length of time trade accounts are past due, the customer s ability to pay its obligations to CVR, and the condition of the general economy and the industry as a whole. CVR writes off accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. At December 31, 2006 and December 31, 2007, two customers individually represented greater than 10% and collectively represented 29% and 29%, respectively, of the total accounts receivable balance. The largest concentration of credit for any one customer at December 31, 2006 and December 31, 2007 was 16% and 15%, respectively, of the accounts receivable balance.

Inventories

Inventories consist primarily of crude oil, blending stock and components, work in progress, fertilizer products, and refined fuels and by-products. Inventories are valued at the lower of the first-in, first-out (FIFO) cost, or market for fertilizer products, refined fuels and by-products for all periods presented. Refinery unfinished and finished products inventory values were determined using the ability-to-bare process, whereby raw materials and production costs are allocated to work-in-process and finished products based on their relative fair values. Other inventories, including other raw materials, spare parts, and supplies, are valued at the lower of moving average cost, which approximates FIFO, or market. The cost of inventories includes inbound freight costs.

Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist of prepayments for crude oil deliveries to the refinery for which title had not transferred, non-trade accounts receivables, current portions of prepaid insurance and deferred financing costs, and other general current assets.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Property, Plant, and Equipment

Additions to property, plant and equipment, including capitalized interest and certain costs allocable to construction and property purchases, are recorded at cost. Capitalized interest is added to any capital project over $1,000,000 in cost which is expected to take more than six months to complete. Depreciation is computed using principally the straight-line method over the estimated useful lives of the various classes of depreciable assets. The lives used in computing depreciation for such assets are as follows:

Asset	Range of Useful Lives, in Years
Improvements to land	15 to 20
Buildings	20 to 30
Machinery and equipment	5 to 30
Automotive equipment	5
Furniture and fixtures	3 to 7

Our leasehold improvements are depreciated on the straight-line method over the shorter of the contractual lease term or the estimated useful life. Expenditures for routine maintenance and repair costs are expenses when incurred. Such expenses are reported in direct operating expenses (exclusive of depreciation and amortization) in the Company s consolidated statements of operations.

Goodwill and Intangible Assets

Goodwill represents the excess of the cost of an acquired entity over the fair value of the assets acquired less liabilities assumed. Intangible assets are assets that lack physical substance (excluding financial assets). Goodwill acquired in a business combination and intangible assets with indefinite useful lives are not amortized, and intangible assets with finite useful lives are amortized. Goodwill and intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset might be impaired. CVR uses November 1 of each year as its annual valuation date for the impairment test. The annual review of impairment is performed by comparing the carrying value of the applicable reporting unit to its estimated fair value, using a combination of the discounted cash flow analysis and market approach. Our reporting units are defined as operating segments due to each operating segment containing only one component. As such all goodwill impairment testing is done at each operating segment.

Deferred Financing Costs

Deferred financing costs related to the term debt are amortized to interest expense and other financing costs using the effective-interest method over the life of the term debt. Deferred financing costs related to the revolving loan facility and the funded letters of credit facility are amortized to interest expense and other financing costs using the straight-line method through the termination date of each credit facility.

Planned Major Maintenance Costs

The direct-expense method of accounting is used for planned major maintenance activities. Maintenance costs are recognized as expense when maintenance services are performed. During the year ended December 31, 2006, the Coffeyville nitrogen plant completed a major scheduled turnaround. Costs of approximately $2,570,000 associated with the turnaround are included in direct operating expenses (exclusive of depreciation and amortization). The Coffeyville refinery completed a major scheduled turnaround in 2007. Costs of approximately $3,984,000 and $76,393,000, associated with the 2007 turnaround, were included in direct operating expenses (exclusive of depreciation and amortization) for the year ended December 31, 2006 and December 31, 2007, respectively.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Planned major maintenance activities for the nitrogen plant generally occur every two years. The required frequency of the maintenance varies by unit, for the refinery, but generally is every four years.

Cost Classifications

Cost of product sold (exclusive of depreciation and amortization) includes cost of crude oil, other feedstocks, blendstocks, pet coke expense and freight and distribution expenses. Cost of product sold excludes depreciation and amortization of approximately $149,806, $1,061,217, $2,147,778, and $2,389,558 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 December 31, 2007, respectively.

Direct operating expenses (exclusive of depreciation and amortization) includes direct costs of labor, maintenance and services, energy and utility costs, environmental compliance costs as well as chemicals and catalysts and other direct operating expenses. Direct operating expenses exclude depreciation and amortization of approximately $906,718, $22,706,227, $47,714,060, and $57,367,166 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 December 31, 2007, respectively. Direct operating expenses also exclude depreciation of $7,627,073 for the year ended December 31, 2007 that is included in Net Costs Associated with Flood on the consolidated statement of operations as a result of the assets being idle due to the flood.

Selling, general and administrative expenses (exclusive of depreciation and amortization) consist primarily of legal expenses, treasury, accounting, marketing, human resources and maintaining the corporate offices in Texas and Kansas. Selling, general and administrative expenses excludes depreciation and amortization of approximately $71,481, $186,587, $1,142,744, and $1,022,451 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 December 31, 2007, respectively.

Income Taxes

CVR accounts for income taxes under the provision of Statement Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*. SFAS 109 requires the asset and liability approach for accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for the anticipated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred amounts are measured using enacted tax rates expected to apply to taxable income in the year those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

As discussed in Note 10, (Income Taxes) CVR adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB No. 109* (FIN 48) effective January 1, 2007.

Consolidation of Variable Interest Entities

In accordance with FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities*, (FIN 46R), management has reviewed the terms associated with its interests in the Partnership based upon the partnership agreement. Management has determined that the Partnership is a variable interest entity (VIE) and as such has evaluated the criteria under FIN 46R to determine that CVR is 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

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

additional subordinated financial support. As the primary beneficiary, CVR absorbs the majority of the expected losses and/or receives a majority of the expected residual returns of the VIE s activities.

Impairment of Long-Lived Assets

CVR accounts for 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.

Revenue Recognition

Revenues for products sold are recorded upon delivery of the products to customers, which is the point at which title is transferred, the customer has the assumed risk of loss, and when payment has been received or collection is reasonably assumed. Deferred revenue represents customer prepayments under contracts to guarantee a price and supply of nitrogen fertilizer in quantities expected to be delivered in the next 12 months in the normal course of business. Excise and other taxes collected from customers and remitted to governmental authorities are not included in reported revenues.

Shipping Costs

Pass-through finished goods delivery costs reimbursed by customers are reported in net sales, while an offsetting expense is included in cost of product sold (exclusive of depreciation and amortization).

Derivative Instruments and Fair Value of Financial Instruments

CVR uses futures contracts, options, and forward swap contracts primarily to reduce the exposure to changes in crude oil prices, finished goods product prices and interest rates and to provide economic hedges of inventory positions. These derivative instruments have not been designated as hedges for accounting purposes. Accordingly, these instruments are recorded in the consolidated balance sheets at fair value, and each period s gain or loss is recorded as a component of gain (loss) on derivatives in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value, as a result of the short-term nature of the instruments. The carrying value of long-term and revolving debt approximates fair value as a result of the floating interest rates assigned to those financial instruments.

Share-Based Compensation

CVR, CALLC, CALLC II and CALLC III account for share-based compensation in accordance with SFAS No. 123(R), *Share-Based Payments* and EITF 00-12 Issue No. 00-12, *Accounting by an Investor for Stock-Based Compensation Granted to Employees of an Equity Method Investee* (EITF 00-12). CVR has been allocated non-cash share-based compensations expense from CALLC, CALLC II and CALLC III.

In accordance with SFAS 123(R), CVR, CALLC, CALLC II and CALLC III apply a fair-value based measurement method in accounting for share-based compensation. In accordance with EITF 00-12, CVR

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

recognizes the costs of the share-based compensation incurred by CALLC, CALLC II and CALLC III on its behalf, primarily in selling, general, and administrative expenses (exclusive of depreciation and amortization), and a corresponding capital contribution, as the costs are incurred on its behalf, following the guidance in EITF Issue No. 96-18, *Accounting for Equity Investments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling Goods or Services*, which requires variable accounting in the circumstances.

Non-vested shares, when granted, are valued at the closing market price of CVR s common stock on the date of issuance and amortized to compensation expense on a straight-line basis over the vesting period of the stock. The fair value of the stock options is estimated on the date of grant using the Black Scholes option pricing model.

As of December 31, 2007, there had been 17,500 shares of non-vested common stock awarded. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have voting and non-forfeitable dividend rights on these shares from the date of grant. See Note 3, Share-Based Compensation .

Environmental Matters

Liabilities related to future remediation costs of past environmental contamination of 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, internal and third-party assessments of contamination, available remediation technology, site-specific costs, and currently enacted laws and regulations. In reporting environmental liabilities, no offset is made for potential recoveries. Loss contingency accruals, including those for environmental remediation, are subject to revision as further information develops or circumstances change and such accruals can take into account the legal liability of other parties. Environmental expenditures are capitalized at the time of the expenditure when such costs provide future economic benefits.

Use of Estimates

The consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles, using management s best estimates and judgments where appropriate. These estimates and judgments affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from these estimates and judgments.

New Accounting Pronouncements

In September 2006, the FASB issued FAS No. 157, *Fair Value Measurements*, which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. FAS 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 statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently evaluating the effect that this statement will have on its financial statements.

In February 2007, the FASB issued FAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (FAS 159). 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

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

FAS 157 and FAS No. 107, *Disclosures about Fair Value of Financial Instruments*. FAS 159 is effective for fiscal years beginning after November 15, 2007, and early adoption is permitted as of January 1, 2007, provided that the entity makes that choice in the first quarter of 2007 and also elects to apply the provisions of FAS 157. We are currently evaluating the potential impact that FAS 159 will have on our financial condition, results of operations and cash flows.

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 noncontrolling 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 will be required to adopt this statement as of January 1, 2009. The impact of adopting SFAS 141R 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, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling 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 us beginning January 1, 2009. The Company is currently evaluating the potential impact of the adoption of SFAS 160 on its consolidated financial statements.

(3) Members Equity and Share Based Compensation

Management of Immediate Predecessor was issued 11,152,941 nonvoting restricted common units for recourse promissory notes aggregating $63,000. Concurrent with the Acquisition at June 23, 2005, as described in note 1, all of the restricted common units of management were fully vested. Immediate Predecessor recognized $3,985,991 in compensation expense for the 174-day period ended June 23, 2005, related to earned compensation.

On June 23, 2005, immediately prior to the Acquisition (see note 1), the Immediate Predecessor used available cash balances to distribute a $52,211,493 dividend 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.

Successor issued 22,766,000 voting common units at $10 par value for cash to finance the Acquisition, as described in note 1. An additional 50,000 voting common units at $10 par value were issued to a member of management for an unsecured recourse promissory note that accrued interest at 7% and required annual principal and interest payments through December 2009. The unpaid balance of the unsecured recourse promissory note and all unpaid interest was forgiven September 25, 2006 (see note 16).

As required by the term loan agreements to fund certain capital projects, on September 14, 2005 an additional $10,000,000 capital contribution was received in return for 1,000,000 voting common units and on May 23, 2006 an additional $20,000,000 capital contribution was received in return for 2,000,000 at $10 par value (Delayed Draw

Capital).

Common units held by management contained put rights held by management and call rights held by CALLC exercisable at fair value in the event the management member became inactive. Accordingly, in accordance with EITF Topic No. D-98, *Classification and Measurement of Redeemable Securities*, common units held by management were initially recorded at fair value at the date of issuance and were classified in temporary equity as Management Voting Common Units Subject to Redemption (Capital Subject to Redemption) in the accompanying consolidated balance sheets. The put rights and call rights were eliminated in October 2007.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On November 30, 2006, an amendment to the Second Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition LLC was approved with a pro rata reduction among all holders of common units in order to effect a total reduction of the number of outstanding Common Units. This amendment reduced the number of outstanding Common Units by 11.62%. Because cash unit holder s value and ownership interest before and after the reallocation is unchanged and since no transfer of value occurred among the common unit holders, this pro rata reduction had no accounting consequence. At December 31, 2006, management held 201,063 of the 22,816,000 voting common units.

On December 28, 2006, successor refinanced its existing long-term debt with $775 million term loan and used the proceeds of the borrowings to repay the outstanding borrowings under its previous first and second lien credit facilities, pay related fees and expenses and pay a distribution of $250 million to its common unit holders at December 31, 2006.

The put rights with respect to management s common units, provide that following their termination of employment, they have the right to sell all (but not less than all) of their common units to Coffeyville Acquisition LLC at their Fair Market Value (as that term is defined in the LLC Agreement) if they were terminated without Cause , or as a result of death, Disability or resignation with Good Reason (each as defined in the LLC Agreement) or due to Retirement (as that term is defined in the LLC Agreement). Coffeyville Acquisition LLC has call rights with respect to the executives common units, so that following the executives termination of employment, Coffeyville Acquisition LLC has the right to purchase the common units at their Fair Market Value if the executive was terminated without Cause, or as a result of the executives death, Disability or resignation with Good Reason or due to Retirement. The call price will be the lesser of the common unit s Fair Market Value or Carrying Value (which means the capital contribution, if any, made by the executive in respect of such interest less the amount of distributions made in respect of such interest) if the executive is terminated for Cause or he resigns without Good Reason. For any other termination of employment, the call price will be at the Fair Market Value or Carrying Value of such common units, in the sole discretion of Coffeyville Acquisition LLC s board of directors. No put or call rights apply to override units following the executive s termination of employment unless Coffeyville Acquisition LL s board of directors (or the compensation committee thereof) determines in its discretion that put and call rights will apply.

CVR accounts for changes in redemption value of management common units in the period the changes occur and adjusts the carrying value of the Management Voting Common Units Subject to Redemption to equal the redemption value at the end of each reporting period with an equal and offsetting adjustment to Members Equity. None of the Management Voting Common Units Subject to Redemption were redeemable at December 31, 2005 or December 31, 2006.

At December 31, 2005 the Management Voting Common Units Subject to Redemption were revalued through an independent appraisal process, and the value was determined to be $18.34 per unit. Accordingly, the carrying value of the Management Voting Common Units Subject to Redemption increased by $3,035,586 for the 233-day period ended December 31, 2005 with an equal and offsetting decrease to Members Equity.

At December 31, 2006, the Management Voting Common Units Subject to Redemption were revalued through an independent appraisal process, and the value was determined to be $34.72 per unit. The appraisal utilized a discounted cash flow (DCF) method, a variation of the income approach, and the guideline public company method, a variation of the market approach, to determine the fair value. The guideline public company method utilized a weighting of market multiples from publicly-traded petroleum refiners and fertilizer manufactures that are comparable to the Company. The recognition of the value of $34.72 per unit increased the carrying value of the Management Voting Common Units Subject to Redemption by $4,239,548 for the year ended December 31, 2006 with an equal and offsetting decrease to Members Equity. This increase was the result of higher forward market price assumptions, which were consistent with what was observed in the market during the period, in the refining business resulting in increased free cash flow

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

projections utilized in the DCF method. The market multiples for the public-traded comparable companies also increased from December 31, 2005, resulting in increased value of the units.

Concurrent with the Subsequent Acquisition, Successor issued nonvoting override operating units to certain management members who hold common units. There were no required capital contributions for the override operating units.

Upon completion of the initial public offering on October 26, 2007, members equity, Management Voting Common Units Subject to Redemption, and Management Nonvoting Override Units were eliminated and replaced with Stockholders Equity to reflect the new corporate structure.

The following describes the share-based compensation plans of CALLC, CALLC II, CALLC III and CRLLC, CVR Energy s wholly owned subsidiary.

919,630 override operating units at an adjusted benchmark value of $11.31 per unit

In June 2005, CALLC issued nonvoting override operating units to certain management members holding common units of CALLC. There were no required capital contributions for the override operating units. In accordance with SFAS 123(R), *Share Based Compensation*, using the Monte Carlo method of valuation, the estimated fair value of the override operating units on June 24, 2005 was $3,604,950. Pursuant to the forfeiture schedule described below, CVR Energy recognized compensation expense over the service period for each separate portion of the award for which the forfeiture restriction lapsed as if the award was, in-substance, multiple awards. Compensation expense was $602,381, $1,157,206, and $10,674,537 for the 191-day period ending December 31, 2005, and for the years ending December 31, 2006 and 2007, respectively. In connection with the split of CALLC into two entities on October 16, 2007, management s equity interest in CALLC was split so that half of management s equity interest is in CALLC and half is in CALLC II. The restructuring resulted in a modification of the existing awards under SFAS 123(R). However, because the fair value of the modified award equaled the fair value of the original award before the modification, there was no accounting consequence as a result of the modification. However, due to the restructuring, the employees of CVR Energy and CVR Partners no longer hold share-based awards in a parent company. Due to the change in status of the employees related to the awards, CVR Energy recognized compensation expense for the newly measured cost attributable to the remaining vesting (service) period prospectively from the date of the change in status, which expense is included in the amounts noted above. Also, CVR Energy now accounts for these awards pursuant to EITF 00-12 following the guidance in EITF 96-18, which requires variable accounting in this circumstance. Using a binomial model and a probability-weighted expected return method which utilized CVR Energy s cash flow projections resulted in an estimated fair value of the override operating units as noted below.

Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Explicit service period	Based on forfeiture schedule below	Based on forfeiture schedule below

Grant date; fair value controlling basis	$5.16 per share	
October 16, 2007 (date of modification) estimated fair value		$39.53
December 31, 2007 estimated fair value	N/A	$51.84 per share
Marketability and minority interest discounts	24% discount	15% discount
Volatility	37%	35.8%

138

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

72,492 override operating units at a benchmark value of $34.72 per unit

On December 28, 2006, CALLC issued additional nonvoting override operating units to a certain management member who holds common units of CALLC. There were no required capital contributions for the override operating units. In accordance with SFAS 123(R), a combination of a binomial model and a probability-weighted expected return method which utilized CVR Energy s cash flow projections resulted in an estimated fair value of the override operating units on December 28, 2006 of $472,648. Management believed that this method was preferable for the valuation of the override units as it allowed a better integration of the cash flows with other inputs, including the timing of potential exit events that impact the estimated fair value of the override units. These override operating units are being accounted for the same as the override operating units with the adjusted benchmark value of $11.31 per unit. In accordance with that accounting method noted above and pursuant to the forfeiture schedule described below, CVR recognized compensation expense of $3,324 and $877,135 for the periods ending December 31, 2006 and 2007, respectively. The amount included in the year ending December 31, 2007 includes compensation expense as a result of the restructuring and modification of the split of CALLC into two entities, as described above. Using a binomial model and a probability-weighted expected return method which utilized CVR Energy s cash flow projections resulted in an estimated fair value of the override operating units as described below.

Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Explicit service period	Based on forfeiture schedule below	Based on forfeiture schedule below
Grant date; fair value controlling basis	$8.15 per share	
October 16, 2007 (date of modification) estimated fair value		$20.34
December 31, 2007 estimated fair value	N/A	$32.65 per share
Marketability and minority interest discounts	20% discount	15% discount
Volatility	41%	35.8%

Override operating units are forfeited upon termination of employment for cause. In the event of all other terminations of employment, the override operating units are initially subject to forfeiture with the number of units subject to forfeiture reducing as follows:

Minimum Period Held	Forfeiture Percentage
2 years	75%
3 years	50%
4 years	25%
5 years	0%

On the tenth anniversary of the issuance of override operating units, such units shall convert into an equivalent number of override value units.

1,839,265 override value units at an adjusted benchmark value of $11.31 per unit

In June 2005, CALLC issued 1,839,265 nonvoting override value units to certain management members holding common units of CALLC. There were no required capital contributions for the override value units.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In accordance with SFAS 123(R), using the Monte Carlo method of valuation, the estimated fair value of the override value units on June 24, 2005 was $4,064,776. For the override value units, CVR Energy is recognizing compensation expense ratably over the implied service period of 6 years. These override value units are being accounted for the same as the override operating units with an adjusted benchmark value of $11.31 per unit. In accordance with that accounting method noted above, CVR recognized compensation expense of $395,187, $677,463, and $12,788,486 for the 191-day period ending December 31, 2005, and for the years ending December 31, 2006 and 2007, respectively. The amount included in the year ending December 31, 2007 includes compensation expense as a result of the restructuring and modification of the split of CALLC into two entities, as described above. Using a binomial model and a probability-weighted expected return method which utilized CVR Energy s cash flow projections resulted in an estimated fair value of the override value units as described below. Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Derived service period	6 years	6 years
Grant date; fair value controlling basis	$2.91 per share	
October 16, 2007 (date of modification) estimated fair value		$39.53
December 31, 2007 estimated fair value	N/A	$51.84 per share
Marketability and minority interest discounts	24% discount	15% discount
Volatility	37%	35.8%

144,966 override value units at a benchmark value of $34.72 per unit

On December 28, 2006, CALLC issued 144,966 additional nonvoting override value units to a certain management member who holds common units of CALLC. There were no required capital contributions for the override value units.

In accordance with SFAS 123(R), a combination of a binomial model and a probability-weighted expected return method which utilized CVR Energy s cash flow projections resulted in an estimated fair value of the override value units on December 28, 2006 of $945,178. Management believed that this method was preferable for the valuation of the override units as it allowed a better integration of the cash flows with other inputs, including the timing of potential exit events that impact the estimated fair value of the override units. For the override value units, CVR Energy is recognizing compensation expense ratably over the implied service period of 6 years. These override value units are being accounted for the same as the override operating units with the adjusted benchmark value of $11.31 per unit. In accordance with that accounting method noted above, CVR recognized compensation expense of $17,185, and $718,293 for the years ending December 31, 2006 and 2007, respectively. The amount included in the year ending December 31, 2007 includes compensation expense as a result of the restructuring and modification of the split of CALLC into two entities, as described above. Using a binomial model and a probability-weighted expected return method which utilized CVR Energy s cash flow projections resulted in an estimated fair value of the override value units as noted below.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Derived service period	6 years	6 years
Grant date; fair value controlling basis	$8.15 per share	
October 16, 2007 (date of modification) estimated fair value		$20.34
December 31, 2007 estimated fair value	N/A	$32.65 per share
Marketability and minority interest discounts	20% discount	15% discount
Volatility	41%	35.8%

Unless the compensation committee of the board of directors of CVR Energy takes an action to prevent forfeiture, override value units are forfeited upon termination of employment for any reason except that in the event of termination of employment by reason of death or disability, all override value units are initially subject to forfeiture with the number of units subject to forfeiture reducing as follows:

Minimum Period Held	Forfeiture Percentage
2 years	75%
3 years	50%
4 years	25%
5 years	0%

At December 31, 2007, assuming no change in the estimated fair value at December 31, 2007, there was approximately $71.1 million of unrecognized compensation expense related to nonvoting override units. This is expected to be recognized over a period of five years as follows (in thousands):

Year ending December 31,	Override Operating Units	Override Value Units
2008	$ 7,882	$ 16,924
2009	4,087	16,924
2010	1,217	16,924
2011		7,138
	$ 13,186	$ 57,910

Phantom Unit Appreciation Plan

CVR Energy, through a wholly-owned subsidiary, has a Phantom Unit Appreciation Plan whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. Holders of service phantom points have rights to receive distributions when holders of override operating units receive distributions. Holders of performance phantom points have rights to receive distributions when holders of override value units receive distributions. There are no other rights or guarantees, and the plan expires on July 25, 2015, or at the discretion of the compensation committee of the board of directors of CVR Energy. As of December 31, 2007, the issued Profits Interest (combined phantom plan and override units) represented 15% of combined common unit interest and Profits Interest of CVR Energy. The Profits Interest was comprised of 11.1% and 3.9% of override interest and phantom interest, respectively. In accordance with SFAS 123(R), using the December 31, 2007 CVR Energy stock closing price to determine the CVR Energy equity value, through an independent valuation process, the service phantom interest and the performance phantom interest were both valued at $51.84 per point. CVR has

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

recorded compensation expense related to the Phantom Unit Plan of $95,019, $10,722,371, and $18,399,504 for the 191-day period ending December 31, 2005, and for the years ending December 31, 2006 and December 31, 2007, respectively. $10,817,390 and $29,216,894 were recorded in personnel accruals as of December 31, 2006 and 2007, respectively.

At December 31, 2007, and assuming no change in the estimated fair value at December 31, 2007, there was approximately $25.2 million of unrecognized compensation expense related to the Phantom Unit Plan. This is expected to be recognized over a remaining period of four years.

138,281 override units with a benchmark amount of $10

In October 2007, CALLC III issued non-voting override units to certain management members holding common units of CALLC III. There were no required capital contributions for the override units. In accordance with SFAS 123(R), *Share Based Compensation*, using a binomial and a probability-weighted expected return method which utilized the CALLC III s cash flows projections, the estimated fair value of the operating units at December 31, 2007 was $2,766. CVR Energy recognizes compensation costs for this plan based on the fair value of the awards at the end of each reporting period in accordance with EITF 00-12 using the guidance in EITF 96-18. In accordance with EITF 00-12, as a noncontributing investor, CVR Energy also recognized income equal to the amount that its interest in the investee s net book value has increased (that is, its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation costs. This amount equaled the compensation expense recognized for these awards for the year ended December 31, 2007. Pursuant to the forfeiture schedule reflected above, CVR Energy recognized compensation expense over this service period for each portion of the award for which the forfeiture restriction has lapsed.

Significant Assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Explicit Service Period	Based on forfeiture schedule above
December 31, 2007 estimated fair value	$0.02 per share
Marketability and minority interest discount	15% discount
Volatility	34.7%

In connection with the initial public offering, the fractional shares held by the Company s chief executive officer in the Successor s subsidiaries were exchanged at the fair value for 247,471 shares of CVR common stock. This exchange resulted in the elimination of the minority interest, the reversal of previous fair value adjustments of $1,053,248 in Members Equity, the step-up in property, plant and equipment of $974,340, and the recognition of a related deferred tax liability of $388,518.

In February 2008, CALLC III issued additional non-voting override units to management members.

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 the Company s 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 the Company s executive officers.

Shares Available for Issuance. The LTIP authorizes a share pool of 7,500,000 shares of the Company s common stock, 1,000,000 of which may be issued in respect of incentive stock options. Whenever any

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

On October 24, 2007, 17,500 shares of non-vested stock having a fair value of $365,400 at the date of grant were issued to outside directors. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have dividend and voting rights on these shares from the date of grant. The fair value of each share of non-vested stock was measured based on the market price of the common stock as of the date of grant and will be amortized over the respective vesting periods. One-third will vest on October 24, 2010.

Options to purchase 10,300 common shares at an exercise price of $19.00 per share were granted to outside directors on October 22, 2007. Options to purchase 8,600 common shares at an exercise price of $24.73 per share were granted to outside directors on December 21, 3007.

A summary of the status of CVR s non-vested shares as of December 31, 2007 and changes during the year ended December 31, 2007 is presented below:

Non-Vested Shares	Shares (In 000 s)	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2006	$	$
Granted	18	20.88
Vested		
Forfeited		
Non-vested at December 31, 2007	$ 18	$ 20.88

As of December 31, 2007, there was approximately $0.3 million of total unrecognized compensation cost related to non-vested shares to be recognized over a weighted-average period of approximately one year. Total compensation expense recorded in 2007 related to the nonvested stock was $41,599.

Activity and price information regarding CVR s stock options granted are summarized as follows:

	Weighted Average	Weighted Average Remaining

Options	Shares (In 000 s)	Exercise Price	Contractual Term
Outstanding, December 31, 2006		$	
Granted	19	$ 21.61	9.89
Exercised			
Forfeited			
Expired			
Outstanding, December 31, 2007	19	$ 21.61	9.89
Vested or expected to vest at December 31, 2007			
Exercisable at December 31, 2007			

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted average grant-date fair value of options granted during the year ended December 31, 2007 was $12.47 per share. Total compensation expense recorded in 2007 related to the stock options was $15,474.

(4) Inventories

Inventories consisted of the following (in thousands):

	Successor	
	December 31, 2006	December 31, 2007
Finished goods	$ 59,722	$ 105,702
Raw materials and catalysts	60,810	91,564
In-process inventories	18,441	28,637
Parts and supplies	22,460	23,340
	$ 161,433	$ 249,243

(5) Property, Plant, and Equipment

A summary of costs for property, plant, and equipment is as follows (in thousands):

	Successor	
	December 31, 2006	December 31, 2007
Land and improvements	$ 11,028	$ 13,058
Buildings	11,042	17,541
Machinery and equipment	864,140	1,108,858
Automotive equipment	4,175	5,171
Furniture and fixtures	5,364	6,304
Leasehold improvements	887	929
Construction in progress	184,531	182,046
	1,081,167	1,333,907
Accumulated depreciation	74,011	141,733
	$ 1,007,156	$ 1,192,174

Capitalized interest recognized as a reduction in interest expense for the years ended December 31, 2006, and December 31, 2007 totaled approximately $11,613,211 and $12,049,104, respectively.

(6) Goodwill and Intangible Assets

In connection with the Acquisition described in note 1, Successor recorded goodwill of $83,774,885. SFAS No. 142, *Goodwill and Other Intangible Assets*, provides that goodwill and other intangible assets with indefinite lives shall not be amortized but shall be tested for impairment on an annual basis. In accordance with SFAS 142, Successor completed its annual test for impairment of goodwill as of November 1, 2006 and 2007. Based on the results of the test, no impairment of goodwill was recorded as of December 31, 2006 or December 31, 2007. The annual review of impairment is performed by comparing the carrying value of the applicable reporting unit to its estimated fair value using a combination of the discounted cash flow analysis and market approach. CVR s reporting units are defined as operating segments, as such all goodwill impairment testing is done at each operating segment.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Contractual agreements with a fair market value of $1,322,000 were acquired in the Acquisition described in note 1. The intangible value of these agreements is amortized over the life of the agreements through June 2025. Amortization expense of $313,453, $370,091, and $164,964 was recorded in depreciation and amortization for the 233-days ended December 31, 2005, and the years ended December 31, 2006, and December 31, 2007, respectively.

Estimated amortization of the contractual agreements is as follows (in thousands):

Year Ending December 31,	Contractual Agreements
2008	64
2009	33
2010	33
2011	33
2012	28
Thereafter	282
	473

(7) Deferred Financing Costs

Deferred financing costs of $10,009,193 were paid in conjunction with a debt financing in 2004. The unamortized amount of these deferred financing costs of $8,093,754 related to the May 10, 2004 refinancing were written off when the related debt was extinguished upon the Acquisition described in note 1 and these costs were included in loss on extinguishment of debt for the 174 days ended June 23, 2005. For the 174 days ended June 23, 2005, amortization of deferred financing costs reported as interest expense and other financing costs was $812,166, using the effective-interest amortization method.

Deferred financing costs of $24,628,315 were paid in the Acquisition described in note 1. Effective December 28, 2006, the Company amended and restated its credit agreement with a consortium of banks, additionally capitalizing $8,462,390 in debt issuance costs. This amendment and restatement was within the scope of the EITF 96-19, *Debtor s Accounting for Modification or Exchange of Debt Instruments*, as well as EITF 98-14, *Debtor s Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*. In accordance with that guidance, a portion of the unamortized loan costs of $16,959,015 from the original credit facility as well as additional finance and legal charges associated with the second amended and restated credit facility of $901,291 were included in loss on extinguishment of debt for the year December 31, 2006. The remaining costs are being amortized over the life of the related debt instrument. Additionally, a prepayment penalty of $5,500,000 on the previous credit facility was also paid and expensed and included in loss on extinguishment of debt for the year ended December 31, 2006. For the 233 days ended December 31, 2005, the years ended December 31, 2006, and December 31, 2007, amortization of deferred financing costs reported as interest expense and other financing costs totaled $1,751,041, $3,336,795, and $1,946,818, respectively, using the effective-interest amortization method for the term debt and the straight-line method for the letter of credit facility and revolving loan facility.

Deferred financing costs of $2,088,451 were paid in conjunction with three new credit facilities entered into August 2007 as a result of the flood and crude oil discharge. The unamortized amount of these deferred financing costs of $1,257,764 were written off when the related debt was extinguished upon the consummation of the initial public offering and these costs were included in loss on extinguishment of debt for the year ended December 31, 2007. Amortization of deferred financing costs reported as interest expense and other financing costs was $830,687 using the effective-interest amortization method.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred financing costs consisted of the following (in thousands):

	December 31, 2006	December 31, 2007
Deferred financing costs	$ 11,065	$ 12,278
Less accumulated amortization	21	2,778
Unamortized deferred financing costs	11,044	9,500
Less current portion	1,916	1,985
	$ 9,128	$ 7,515

Estimated amortization of deferred financing costs is as follows (in thousands):

Year Ending December 31,	Deferred Financing
2008	$ 1,985
2009	1,968
2010	1,953
2011	1,436
2012	1,426
Thereafter	732
	$ 9,500

(8) Note Payable and Capital Lease Obligations

The Company entered into an insurance premium finance agreement in July 2007 to finance the purchase of its property, liability, cargo and terrorism policies. The approximately $3.4 million note will be repaid in equal monthly installments of $0.8 million with final payment in April 2008.

The Company entered into two capital leases in 2007 to lease platinum required in the manufacturing of a new catalyst. The leases will terminate on the date an equal amount of platinum is returned to each lessor with the difference to be paid in cash. At December 31, 2007 the lease obligations were recorded at approximately $8.2 million on the consolidated balance sheet.

(9) Flood

On June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville, Kansas. As a result, the Company s refinery and nitrogen fertilizer plant were severely flooded resulting in significant damage to the refinery assets. The nitrogen fertilizer facility also sustained damage, but to a much lesser degree. The Company maintains property damage insurance which includes damage caused by a flood of up to $300 million per occurrence subject to deductibles and other limitations. The deductible associated with the property damage is $2.5 million.

Management is working closely with the Company s insurance carriers and claims adjusters to ascertain the full amount of insurance proceeds due to the Company as a result of the damages and losses. The Company has recognized a receivable of approximately $85.3 million from insurance at December 31, 2007 which management believes is probable of recovery from the insurance carriers. While management believes that the Company s property insurance should cover substantially all of the estimated total physical damage to the property, the Company s insurance carriers have cited potential coverage limitations and defenses that might preclude such a result.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s insurance policies also provide coverage for interruption to the business, including lost profits, and reimbursement for other expenses and costs the Company has incurred relating to the damages and losses suffered for business interruption. This coverage, however, only applies to losses incurred after a business interruption of 45 days. Because the fertilizer plant was restored to operation within this 45-day period and the refinery restarted its last operating unit in 48 days, a substantial portion of the lost profits incurred because of the flood cannot be claimed under insurance. The Company is assessing its policies to determine how much, if any, of its lost profits after the 45-day period are recoverable. No amounts for recovery of lost profits under the Company s business interruption policy have been recorded in the accompanying consolidated financial statements.

As of December 31, 2007, the Company has recorded pretax costs of approximately $41.5 million associated with the flood and related crude oil discharge as discussed in Note 14, Commitments and Contingent Liabilities , including $7.2 million in the fourth quarter of 2007. These amounts were net of anticipated insurance recoveries of approximately $105.3 million. The components of the net costs as of December 31, 2007 include $3.6 million for uninsured losses within the Company s insurance deductibles; $7.6 million for depreciation for the temporarily idled facilities; $6.8 million as a result of other uninsured expenses incurred which included salaries of $1.2 million, professional fees of $1.9 million and other miscellaneous amounts of $3.7 million. The $41.5 million net costs also included approximately $23.5 million recorded with respect to the environmental remediation and property damage as discussed in Note 14, Commitments and Contingent Liabilities . These costs are reported in Net costs associated with flood in the Consolidated Statements of Operations.

Total gross costs recorded due to the flood and related oil discharge that were included in the statement of operations for the year ended December 31, 2007 were approximately $146.8 million. Of these gross costs for the year ended December 31, 2007, approximately $101.9 million were associated with repair and other matters as a result of the flood damage to the Company s 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 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 anticipated insurance recoveries of approximately $105.3 million were recorded and netted with the gross costs as of December 31, 2007. As of December 31, 2007, CVR had received insurance proceeds of $10.0 million under its property insurance policy, and an additional $10.0 million under its environmental policies related to the recovery of certain costs associated with the crude oil discharge. Subsequent to December 31, 2007, CVR received insurance proceeds of $1.5 million under the Builder s Risk Insurance Policy. See Note 14, Commitments and Contingent Liabilities for additional information regarding environmental and other contingencies relating to the crude oil discharge that occurred on July 1, 2007. Accounts receivable from insurers for flood related matters approximated $85.3 million at December 31, 2007, for which we believe collection is probable, including $11.4 million related to the crude oil discharge and $73.9 million as a result of the flood damage to the Company s facilities.

The Company anticipates that approximately $6.0 million in additional third party costs related to the repair of flood damaged property will be recorded in future periods. Although the Company believes that it will recover substantial sums under its insurance policies, the Company is not sure of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of the Company s claims. The difference between what the Company ultimately receives under its insurance policies compared to what has been recorded and described above could be material to the consolidated financial statements.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) Income Taxes

Income tax expense (benefit) is comprised of the following (in thousands):

	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
Current				
Federal	$ 26,145	$ 29,000	$ 26,096	$ (20,842)
State	6,099	6,457	6,974	(3,895)
Total current	32,244	35,457	33,070	(24,737)
Deferred				
Federal	3,083	(80,500)	69,836	(21,855)
State	721	(17,925)	16,934	(35,047)
Total deferred	3,804	(98,425)	86,770	(56,902)
Total income tax expense (benefit)	$ 36,048	$ (62,968)	$ 119,840	$ (81,639)

The following is a reconciliation of total income tax expense (benefit) to income tax expense (benefit) computed by applying the statutory federal income tax rate (35%) to income before income tax expense (benefit) (in thousands):

	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
Tax computed at federal statutory rate	$ 30,956	$ (63,744)	$ 108,994	$ (48,535)
State income taxes, net of federal tax benefit (expense)	4,433	(7,454)	15,618	(5,520)
State tax incentives, net of deferred federal tax expense			(78)	(19,792)
Manufacturing activities deduction	(825)	(897)	(1,089)	
Federal tax credit for production of ultra-low sulfur diesel fuel			(4,462)	(17,259)

Loss on unexercised option agreements with no tax benefit to Successor				8,750				
Non-deductible share based compensation		1,395		349		649		8,771
Other, net		89		28		208		696
Total income tax expense (benefit)	$	36,048	$	(62,968)	$	119,840	$	(81,639)

Certain provisions of the American Jobs Creation Act of 2004 (the Act) are providing federal income tax benefits to CVR. The Act created Internal Revenue Code section 199 which provides an income tax benefit to domestic manufacturers. CVR recognized an income tax benefit related to this manufacturing deduction of approximately $825,000, $897,000, $1,089,000, and $0 for the 174 days ended June 23, 2005, the 233 days ended December 31, 2005, and the years ended December 31, 2006, and December 31, 2007, respectively.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Act also provides for a $0.05 per gallon income tax credit on compliant diesel fuel produced up to an amount equal to the remaining 25% of the qualified capital costs. CVR recognized an income tax benefit of approximately $4,462,000 and $17,259,000 on a credit of approximately $6,865,000 and $26,552,000 related to the production of ultra low sulfur diesel for the years ended December 31, 2006, and December 31, 2007, respectively.

The loss on unexercised option agreements of $25,000,000 in 2005 occurred at Coffeyville Acquisition LLC, and the tax deduction related to the loss was passed through to the partners of Coffeyville Acquisition LLC in the 233 days ended December 31, 2005.

The income tax effect of temporary differences that give rise to significant portions of the deferred income tax assets and deferred income tax liabilities at December 31, 2006 and 2007 are as follows:

	December 31, 2006	December 31, 2007
	(In thousands)	
Deferred income tax assets:		
Allowance for doubtful accounts	$ 150	$ 156
Personnel accruals	5,072	12,757
Inventories	673	671
Unrealized derivative losses, net	40,389	85,650
Low sulfur diesel fuel credit carry forward		17,860
State net operating loss carry forwards, net of federal expense		3,375
Accrued expenses	249	1,713
Deferred revenue		3,403
State tax credit carryforward, net of federal expense		17,475
Other		353
Total Gross deferred income tax assets	46,533	143,413
Deferred income tax liabilities:		
Property, plant, and equipment	(309,472)	(348,901)
Prepaid Expenses	(1,140)	(3,233)
Other	(1,155)	
Total Gross deferred income tax liabilities	(311,767)	(352,134)
Net deferred income tax liabilities	$ (265,234)	$ (208,721)

At December 31, 2007, CVR has net operating loss carryforwards for state income tax purposes of approximately $70.4 million, which are available to offset future state taxable income. The net operating loss carryforwards, if not utilized, will expire between 2012 and 2027.

At December 31, 2007, CVR has federal tax credit carryforwards related to the production of low sulfur diesel fuel of approximately $17.9 million, which are available to reduce future federal regular income taxes. These credits, if not used, will expire in 2027. CVR also has Kansas state income tax credits of approximately $26.9 million, which are available to reduce future Kansas state regular income taxes. These credits, if not used, will expire in 2017.

In assessing the realizability of deferred tax assets including net operating loss and credit carryforwards, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that CVR will realize the benefits of these deductible differences. Therefore, CVR has not recorded any valuation allowances against deferred tax assets as of December 31, 2006 or December 31, 2007.

CVR adopted FIN 48 effective January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the financial statements. If the probability of sustaining a tax position is at least more likely than not, then the tax position is warranted and recognition should be at the highest amount which is greater than 50% likely of being realized upon ultimate settlement. As of the date of adoption of FIN 48 and at December 31, 2007, CVR did not believe it had any tax positions that met the criteria for uncertain tax positions. As a result, no amounts were recognized as a liability for uncertain tax positions.

CVR recognizes interest and penalties on uncertain tax positions and income tax deficiencies in income tax expense. CVR did not recognize any interest or penalties in 2007 for uncertain tax positions or income tax deficiencies. At December 31, 2007, CVR s tax returns are open to examination for federal and various states for the 2004 to 2007 tax years.

A reconciliation of the unrecognized tax benefits for the year ended December 31, 2007, is as follows:

Balance as of January 1, 2007	$ 0
Increase and decrease in prior year tax positions	
Increases and decrease in current year tax positions	
Settlements	
Reductions related to expirations of statute of limitations	
Balance as of December 31, 2007	$ 0

(11) Long-Term Debt

Effective May 10, 2004, Immediate Predecessor entered into a term loan of $150,000,000 and a $75,000,000 revolving loan facility with a syndicate of banks, financial institutions, and institutional lenders. Both loans were secured by substantially all of the Immediate Predecessor s real and personal property, including receivables, contract rights, general intangibles, inventories, equipment, and financial assets. Outstanding borrowings on June 23, 2005 were repaid in connection with the Subsequent Acquisition as described in note 1.

Effective June 24, 2005, Successor entered into a first lien credit facility and a guaranty agreement with two banks and one related party institutional lender (see 16). The credit facility was in an aggregate amount not to exceed $525,000,000, consisting of $225,000,000 Tranche B Term Loans; $50,000,000 of Delayed Draw Term Loans available for the first 18 months of the agreement and subject to accelerated payment terms; a $100,000,000 Revolving Loan Facility; and a Funded Letters of Credit Facility (Funded Facility) of $150,000,000. The credit facility was secured by substantially all of Successor s assets. Outstanding borrowings on December 28, 2006 were repaid in connection with the refinancing described below.

The Term Loans and Revolving Loan Facility provided CVR the option of a 3-month LIBOR rate plus 2.5% per annum (rounded up to the next whole multiple of 1/16 of 1%) or an Index Rate (to be based on the current prime rate plus 1.5%). Interest was paid quarterly when using the Index Rate and at the expiration of the LIBOR term selected when using the LIBOR rate; interest varied with the Index Rate or LIBOR rate in effect at the time of the borrowing. The annual fee for the Funded Facility was 2.725% of outstanding Funded Letters of Credit.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effective June 24, 2005, Successor entered into a second lien $275,000,000 term loan and guaranty agreement with a bank and a related party institutional lender (see note 16). CVR had the option of a 3-month LIBOR rate plus 6.75% per annum (rounded up to the next whole multiple of 1/16 of 1%) or an Index Rate (to be based on the current prime rate plus 5.75%). The loan was secured by a second lien on substantially all of CVR s assets. Outstanding borrowings on December 28, 2006 were repaid in connection with the refinancing described below.

On December 28, 2006, Successor entered into a second amended and restated credit and guaranty agreement (the credit and guaranty agreement) with two banks and one related party institutional lender (see note 16). The credit facility was in an aggregate amount not to exceed $1,075,000,000, consisting of $775,000,000 Tranche D Term Loans; a $150,000,000 Revolving Loan Facility; and a Funded Facility of $150,000,000. The credit facility was secured by substantially all of CVR s assets. At December 31, 2006, and December 31, 2007, $775,000,000 and $489,202,019 of Tranche D Term Loans was outstanding, and there was no outstanding balance on the Revolving Loan Facility. At December 31, 2006, and December 31, 2007, Successor had $150,000,000 in Funded Letters of Credit outstanding to secure payment obligations under derivative financial instruments (see note 15).

At December 31, 2006, the Term Loan and Revolving Loan Facility provided CVR the option of a 3-month LIBOR rate plus 3.0% per annum (rounded up to the next whole multiple of 1/16 of 1%) or an Index Rate (to be based on the current prime rate plus 2.0%). At December 31, 2007, the Term Loan and Revolving Loan Facility provide CVR the option of a 3-month LIBOR rate plus 2.75% per annum (rounded up to the next whole multiple of 1/16 of 1%) or an Index Rate (to be based on the current prime rate plus 1.75%). Interest is paid quarterly when using the Index Rate and at the expiration of the LIBOR term selected when using the LIBOR rate; interest varies with the Index Rate or LIBOR rate in effect at the time of the borrowing. The interest rate on December 31, 2006 and December 31, 2007 was 8.36%and 7.98%, respectively. The annual fee for the Funded Facility was 3.225% and 2.975%, respectively at December 31, 2006 and December 31, 2007 of outstanding Funded Letters of Credit.

The loan and security agreements contain customary restrictive covenants applicable to CVR, including limitations on the level of additional indebtedness, commodity agreements, capital expenditures, payment of dividends, creation of liens, and sale of assets. These covenants also require CVR to maintain specified financial ratios as follows:

First Lien Credit Facility

Fiscal Quarter Ending	Minimum Interest Coverage Ratio	Maximum Leverage Ratio
March 31, 2008	3.25:1.00	3.25:1.00
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 December 31, 2009	3.75:1.00	2.25:1.00
March 31, 2010 and thereafter	3.75:1.00	2.00:1.00

Failure to comply with the various restrictive and affirmative covenants of the loan agreements could negatively affect CVR s ability to incur additional indebtedness and/or pay required distributions. Successor is required to measure its compliance with these financial ratios and covenants quarterly and was in compliance with all covenants and reporting requirements under the terms of the agreement at December 31, 2006 and December 31, 2007. As required by the debt agreements, CVR has entered into interest rate swap agreements (as described in note 15) that are required to be held for the remainder of the stated term.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term debt at December 31, 2007 consisted of the following future maturities:

	Year Ending December 31,	Amount
First lien Tranche D term loans; principal payments	2008	$ 4,873,706
of .25% of the principal balance due quarterly commencing	2009	4,825,151
April 2007, increasing to 23.5% of the principal balance due	2010	4,777,080
quarterly commencing April 2013, with a final	2011	4,729,488
payment of the aggregate remaining unpaid principal balance	2012	4,682,370
due December 2013	Thereafter	465,314,224
		$ 489,202,019

Commencing with fiscal year 2007, CVR shall prepay the loans in an aggregate amount equal to 75% of Consolidated Excess Cash Flow (as defined in the credit and guaranty agreement, which includes a formulaic calculation consisting of many financial statement items, starting with consolidated Earnings Before Interest Taxes Depreciation and Amortization) less 100% of voluntary prepayments made during that fiscal year. Commencing with fiscal year 2008, the aggregate amount changes to 50% of Consolidated Excess Cash Flow provided the total leverage ratio is less than 1:50:1:00 or 25% of Consolidated Excess Cash Flow provided the total leverage ratio is less than 1:00:1:00.

At December 31, 2007, Successor had $5.8 million in letters of credit outstanding to collateralize its environmental obligations, $30.6 million in letters of credit outstanding to secure transportation services for crude oil, and $3.0 million in support of surety bonds in place to support state and federal excise tax for refined fuels. These letters of credit were outstanding against the December 28, 2006 Revolving Loan Facility. The fee for the revolving letters of credit is 3.00%.

The Revolving Loan Facility has a current expiration date of December 28, 2012. The Funded Facility has a current expiration date of December 28, 2010.

As a result of the flood and crude oil discharge, the Company s subsidiaries entered into three new credit facilities in August 2007. Coffeyville Resources, LLC entered into a $25 million senior secured term loan (the $25 million secured facility). The facility was secured by the same collateral that secures the Company s existing Credit Facility. Interest was payable in cash, at the Company s option, at the base rate plus 1.00% or at the reserve adjusted Eurodollar rate plus 2.00%. Coffeyville Resources, LLC also entered into a $25 million senior unsecured term loan (the $25 million unsecured facility). Interest was payable in cash, at the Company s option, at the base rate plus 1.00% or at the reserve adjusted Eurodollar rate plus 2.00%. A subsidiary of Coffeyville Acquisition LLC, Coffeyville Refining & Marketing Holdings, Inc., entered into a $75 million senior unsecured term loan (the $75 million unsecured facility). Drawings could be made from time to time in amounts of at least $5 million. Interest accrued, at the Company s 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.

All indebtedness outstanding under the $25 million secured facility and the $25 million unsecured facility was repaid in October 2007 with the proceeds of the Company s initial public offering, and all three facilities were terminated at that time.

(12) Pro Forma Earnings Per Share

On October 26, 2007, the Company completed the initial public offering of 23,000,000 shares of its common stock. Also, in connection with the initial public offering, a reorganization of entities under common control was consummated whereby the Company became the indirect owner of the subsidiaries of CALLC and

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CALLC II and all of its refinery and fertilizer assets. This reorganization was accomplished by the Company issuing 62,866,720 shares of its common stock to CALLC and CALLC II, its majority stockholder, in conjunction with the merger of two newly formed direct subsidiaries of CVR. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, excluding any non-vested shares issued. See Note 1, Organization and History of Company.

The computation of basic and diluted earnings per share for the years ended December 31, 2006 and December 31, 2007 are calculated on a pro forma basis assuming the capital structure in place after the completion of the offering was in place for the entire year for both 2006 and 2007.

Pro forma earnings (loss) per share for the years ended December 31, 2006 and December 31, 2007 is calculated as noted below. For the year ended December 31, 2007, 17,500 non-vested common shares and 18,900 of 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:

	December 31	
	2006 (Unaudited)	2007 (Unaudited)
	(In thousands)	
Net income (loss)	$ 191,571	$ (56,824)
Pro forma weighted average shares outstanding:		
Original CVR common shares	100	100
Effect of 628,667.20 to 1 stock split	62,866,620	62,866,620
Issuance of common shares to management in exchange for subsidiary shares	247,471	247,471
Issuance of common shares to employees	27,100	27,100
Issuance of common shares in the initial public offering	23,000,000	23,000,000
Basic weighted average shares outstanding	86,141,291	86,141,291
Dilutive securities issuance of nonvested common shares to board of directors	17,500	
Diluted weighted average shares outstanding	86,158,791	86,141,291
Pro forma basic earnings (loss) per share	$ 2.22	$ (0.66)
Pro forma dilutive earnings (loss) per share	$ 2.22	$ (0.66)

(13) Benefit Plans

CVR sponsors two defined-contribution 401(k) plans (the Plans) for all employees. Participants in the Plans may elect to contribute up to 50% of their annual salaries, and up to 100% of their annual income sharing. CVR matches up to 75% of the first 6% of the participant s contribution for the nonunion plan and 50% of the first 6% of the participant s contribution for the union plan. Both plans are administered by CVR and contributions for the union plan are determined in accordance with provisions of negotiated labor contracts. Participants in both Plans are immediately vested in their individual contributions. Both Plans have a three year vesting schedule for CVR s matching funds and contain a provision to count service with any predecessor organization. Successor s contributions under the Plans were $661,922, $446,753, $1,374,914, and $1,512,752 for the 174 days ended June 23, 2005, the 233 days ended December 31, 2005, and the years ended December 31, 2006 and December 31, 2007, respectively.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(14) Commitments and Contingent Liabilities

The minimum required payments for CVR s lease agreements and unconditional purchase obligations are as follows:

Year ending December 31,	Operating Leases	Unconditional Purchase Obligations
2008	4,207,291	25,235,335
2009	3,270,986	25,248,490
2010	1,678,718	52,781,443
2011	946,894	50,958,123
2012	195,438	48,351,815
Thereafter	9,475	366,362,946
	$ 10,308,802	$ 568,938,152

CVR leases various equipment and real properties under long-term operating leases. 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 December 31, 2007, lease expense totaled approximately $1,754,564, $1,737,373, $3,821,833, and $3,854,269, respectively. The lease agreements have various remaining terms. Some agreements are renewable, at CVR s option, for additional periods. It is expected, in the ordinary course of business, that leases will be renewed or replaced as they expire.

CVR licenses a gasification process from a third party associated with gasifier equipment used in the Nitrogen Fertilizer segment. The royalty fees for this license are incurred as the equipment is used and are subject to a cap which was paid in full in 2007. At December 31, 2006, approximately $1,615,000 was included in accounts payable for this agreement. Royalty fee expense reflected in direct operating expenses (exclusive of depreciation and amortization) 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 December 31, 2007 was $1,042,286, $914,878, $2,134,506, and $1,035,296, respectively.

CRNF has an agreement with the City of Coffeyville pursuant to which it must make a series of future payments for electrical generation transmission and city margin. As of December 31, 2007, the remaining obligations of CRNF totaled $19.6 million through December 31, 2019. Total minimum annual committed contractual payments under the agreement will be $1.7 million.

CRRM has a Pipeline Construction, Operation and Transportation Commitment Agreement with Plains Pipeline, L.P. (Plains Pipeline) pursuant to which Plains Pipeline constructed a crude oil pipeline from Cushing, Oklahoma to Caney, Kansas. The term of the agreement is 20 years from when the pipeline became operational on March 1, 2005. Pursuant to the agreement, CRRM must transport approximately 80,000 barrels per day of its crude oil requirements for the Coffeyville refinery at a fixed charge per barrel for the first five years of the agreement. For the final fifteen years of the agreement, CRRM must transport all of its non-gathered crude oil up to the capacity of the Plains

Pipeline. The rate is subject to a Federal Energy Regulatory Commission (FERC) tariff and is subject to change on an annual basis per the agreement. Lease expense associated with this agreement and included in cost of product sold (exclusive of depreciation and amortization) 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 December 31, 2007 totaled approximately $2,603,066, $4,372,115, $8,750,522, and $6,964,992, respectively.

During 1997, Farmland (subsequently assigned to CRP) entered into an Agreement of Capacity Lease and Operating Agreement with Williams Pipe Line Company (subsequently assigned to Magellan Pipe Line Company, L.P. (Magellan)) pursuant to which CRP leases pipeline capacity in certain pipelines between

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Coffeyville, Kansas and Caney, Kansas and between Coffeyville, Kansas and Independence, Kansas. Pursuant to this agreement, CRP was obligated to pay a fixed monthly charge to Magellan for annual leased capacity of 6,300,000 barrels until the expiration of the agreement on April 30, 2007. Lease expense associated with this agreement and included in cost of product sold (exclusive of depreciation and amortization) 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 December 31, 2007 totaled approximately $232,500, $193,750, $503,750, and $116,250, respectively.

During 2005, CRRM amended a Pipeline Capacity Lease Agreement with Mid-America Pipeline Company (MAPL) pursuant to which CRRM leases pipeline capacity in an outbound MAPL-operated pipeline between Coffeyville, Kansas and El Dorado, Kansas for the transportation of natural gas liquids (NGLs) and refined petroleum products. Pursuant to this agreement, CRRM is obligated to make fixed monthly lease payments. The agreement also obligates CRRM to reimburse MAPL a portion of certain permitted costs associated with obligations imposed by certain governmental laws. Lease expense associated with this agreement, included in cost of product sold (exclusive of depreciation and amortization) 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 December 31, 2007, totaled approximately $156,271, $208,316, $800,000, and $800,000, respectively. The lease expires September 30, 2011.

During 2005, CRRM entered into a Pipeage Contract with MAPL pursuant to which CRRM agreed to ship a minimum quantity of NGLs on an inbound pipeline operated by MAPL between Conway, Kansas and Coffeyville, Kansas. Pursuant to the contract, CRRM is obligated to ship 2,000,000 barrels (Minimum Commitment) of NGLs per year at a fixed rate per barrel through the expiration of the contract on September 30, 2011. All barrels above the Minimum Commitment are at a different fixed rate per barrel. The rates are subject to a tariff approved by the Kansas Corporation Commission (KCC) and are subject to change throughout the term of this contract as ordered by the KCC. Lease expense associated with this contract agreement and included in cost of product sold (exclusive of depreciation and amortization) for the 233-day period ended December 31, 2005, and the years ended December 31, 2006 and December 31, 2007, totaled approximately $172,525, $1,612,899, and $1,399,771, respectively.

During 2004, CRRM entered into a Pipeline Capacity Lease Agreement with ONEOK Field Services (OFS) and Frontier El Dorado Refining Company (Frontier) pursuant to which CRRM leases capacity in pipelines operated by OFS between Conway, Kansas and El Dorado, Kansas. Prior to the completion of a planned expansion project specified in the agreement, CRRM will be obligated to pay a fixed monthly charge which will increase after the expansion is complete. The lease expires September 30, 2011. Lease expense associated with this contract agreement and included in cost of product sold (exclusive of depreciation and amortization) for the year ended December 31, 2007 totaled approximately $443,829.

During 2004, CRRM entered into a Transportation Services Agreement with CCPS Transportation, LLC (CCPS) pursuant to which CCPS reconfigured an existing pipeline (Spearhead Pipeline) to transport Canadian sourced crude oil to Cushing, Oklahoma. The term of the agreement is 10 years from the time the pipeline becomes operational, which occurred March 1, 2006. Pursuant to the agreement and pursuant to options for increased capacity which CRRM has exercised, CRRM is obligated to pay an incentive tariff, which is a fixed rate per barrel for a minimum of 10,000 barrels per day. Lease expense associated with this agreement included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2006 and December 31, 2007 totaled approximately $4,608,916 and $6,980,343, respectively.

During 2004, CRRM entered into a Terminalling Agreement with Plains Marketing, LP (Plains) whereby CRRM has the exclusive storage rights for working storage, blending, and terminalling services at several Plains tanks in Cushing, Oklahoma. During 2007, CRRM entered into an Amended and Restated Terminalling Agreement with Plains that replaced the 2004 agreement. Pursuant to the Amended and Restated Terminalling Agreement, CRRM is obligated to pay fees on a minimum throughput volume commitment of 29,200,000 barrels per year. Fees are subject to change annually based on changes in the Consumer Price Index (CPI-U)

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and the Producer Price Index (PPI-NG). Expenses associated with this agreement, included in cost of product sold (exclusive of depreciation and amortization) 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 December 31, 2007, totaled approximately $811,815, $1,251,087, $2,406,093, and $2,396,245, respectively. The original term of the Amended and Restated Terminalling Agreement expires December 31, 2014, but is subject to annual automatic extensions of one year beginning two years and one day following the effective date of the agreement, and successively every year thereafter unless either party elects not to extend the agreement. Concurrently with the above-described Amended and Restated Terminalling Agreement, CRRM entered into a separate Terminalling Agreement with Plains whereby CRRM has obtained additional exclusive storage rights for working storage and terminalling services at several Plains tanks in Cushing, Oklahoma. CRRM is obligated to pay Plains fees based on the storage capacity of the tanks involved, and such fees are subject to change annually based on changes in the Producer Price Index (PPI-FG and PPI-NG). The term of the Terminalling Agreement is split up into two periods based on the tanks at issue, with the term for half of the tanks commencing once they are placed in service (but no later than January 1, 2008), and the term for the remaining half of the tanks commencing October 1, 2008. The original term of the Terminalling Agreement for both sets of tanks expires December 31, 2014, but is subject to annual automatic extensions of one year beginning two years and one day following the effective date of the agreement, and successively every year thereafter unless either party elects not to extend the agreement.

During 2005 CRNF entered into the Amended and Restated On-Site Product Supply Agreement with The Linde Group. Pursuant to the agreement, which expires in 2020, CRNF is required to take as available and pay approximately $300,000 per month, which amount is subject to annual inflation adjustments, for the supply of oxygen and nitrogen to the fertilizer operation. Expenses associated with this agreement, included in direct operating expenses (exclusive of depreciation and amortization) for the years ended December 31, 2006 and December 31, 2007, totaled approximately $3,520,759 and $3,135,969, respectively.

During 2006, CRRM entered into a Lease Storage Agreement with TEPPCO Crude Pipeline, L.P. (TEPPCO) whereby CRRM leases 400,000 barrels of shell capacity at TEPPCO s Cushing tank farm in Cushing, Oklahoma. In September 2006, CRRM exercised its option to increase the shell capacity leased at the facility subject to this agreement from 400,000 barrels to 550,000 barrels. Pursuant to the agreement, CRRM is obligated to pay a monthly per barrel fee regardless of the number of barrels of crude oil actually stored at the leased facilities. Expenses associated with this agreement included in cost of product sold (exclusive of depreciation and amortization) for the year ended December 31, 2007 totaled approximately $1,109,986.

During 2006, CRCT entered into a Pipeline Lease Agreement with Magellan whereby CRCT leases sixty-two miles of eight inch pipeline extending from Humboldt, Kansas to CRCT s facilities located in Broome, Kansas. Pursuant to the lease agreement, CRCT agrees to operate and maintain the leased pipeline and agrees to pay Magellan a fixed annual rental in advance. Expenses associated with this agreement, included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2006 and December 31, 2007 totaled approximately $76,042 and $182,500, respectively. Pursuant to an amendment entered into in 2007, the lease agreement expires on July 31, 2009 with, at the Company s option, up to two one year extensions.

During 2006, CRRM entered into a Transfer Agreement with Magellan pursuant to which CRRM obtained the right to capacity in a pipeline operated by Magellan between Coffeyville, Kansas and El Dorado, Kansas. Pursuant to the agreement, CRRM is obligated to pay a fixed monthly charge for the right to transfer up to 1,000,000 barrels per year through the pipeline. The initial term of the agreement expires on July 14, 2009; however the agreement contains two successive one year additional terms unless CRRM or Magellan provides termination notice as required in the agreement. Expenses associated with this agreement, included in

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cost of product sold (exclusive of depreciation and amortization) for the year ended December 31, 2007 totaled approximately $78,906.

During 2007, CRRM executed a Petroleum Transportation Service Agreement with TransCanada Keystone Pipeline, LP (TransCanada). TransCanada is proposing to construct, own and operate a pipeline system and a related extension and expansion of the capacity that would terminate near Cushing, Oklahoma. TransCanada has agreed to transport a contracted volume amount of at least 25,000 barrels per day with a Cushing Delivery Point as the contract point of delivery. The contract term is a 10 year period which will commence upon the completion of the pipeline system. The expected date of commencement is March 2010 with termination of the transportation agreement estimated to be February 2020. The Company will pay a fixed and variable toll rate beginning during the month of commencement.

CRNF entered into a sales agreement with Cominco Fertilizer Partnership on November 20, 2007 to purchase equipment and materials which comprise a nitric acid plant. CRNF s obligation related to the execution of the agreement in 2007 for the purchase of the assets was $3,500,000. As of December 31, 2007, $250,000 had been paid with $3,250,000 remaining as an accrued current obligation. Additionally, $3,000,000 was accrued related to the obligation to dismantle the unit. These amounts incurred are included in construction-in-progress at December 31, 2007. The total unpaid obligation at December 31, 2007 of $6,250,000 is included in other current liabilities on the Consolidated Balance Sheet.

As a result of the adoption of FIN 47 in 2005, CVR recorded a net asset retirement obligation of $636,000 which was included in other current liabilities at December 31, 2006 and December 31, 2007.

From time to time, CVR is involved in various lawsuits arising in the normal course of business, including matters such as those described below under, Environmental, Health, and Safety Matters, and those described above. Liabilities related to such litigation are recognized when the related costs are probable and can be reasonably estimated. Management believes the company has accrued for losses for which it may ultimately be responsible. It is possible management s estimates of the outcomes will change within the next year due to uncertainties inherent in litigation and settlement negotiations. In the opinion of management, the ultimate resolution of any other litigation matters is not expected to have a material adverse effect on the accompanying consolidated financial statements.

Crude oil was discharged from the Company s refinery on July 1, 2007 due to the short amount of time available to shut down and secure the refinery in preparation for the flood that occurred on June 30, 2007. As a result of the crude oil discharge, two putative class action lawsuits (one federal and one state) were filed seeking unspecified damages with class certification under applicable law for all residents, domiciliaries and property owners of Coffeyville, Kansas who were impacted by the oil release.

The Company filed a motion to dismiss the federal suit for lack of subject matter jurisdiction. On November 6, 2007, the judge in the federal class action lawsuit granted the Company s motion to dismiss for lack of subject matter jurisdiction and no appeal was taken.

The District Court of Montgomery County, Kansas conducted an evidentiary hearing on the issue of class certification on October 24 and 25, 2007 and ruled against the class certification leaving only the original two plaintiffs. To date no other lawsuits have been filed as a result of flood related damages.

As a result of the crude oil discharge that occurred on July 1, 2007, the Company entered into an administrative order on consent (the Consent Order) with the EPA on July 10, 2007. As set forth in the Consent Order, the EPA concluded that the discharge of oil from the Company s refinery caused and may continue to cause an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, the Company agreed to perform specified remedial actions to respond to the discharge of crude oil from the Company s refinery. The Company is currently remediating the crude oil discharge and expects its remedial actions to continue until May 2008.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company engaged experts to assess and test the areas affected by the crude oil spill. The Company commenced a program on July 19, 2007 to purchase approximately 330 homes and other commercial properties in connection with the flood and the crude oil release. The costs recorded as of December 31, 2007 related to the obligation of the homes being purchased, were approximately $13.1 million, and are included in Net Costs Associated With Flood in the accompanying consolidated statement of operations. Costs recorded related to personal property claims were approximately $1.7 million as of December 31, 2007. The costs recorded related to estimated commercial property to be purchased and associated claims were approximately $3.6 million as of December 31, 2007. The total amount of gross costs recorded for the twelve months ended December 31, 2007 related to the residential and commercial purchase and property claims program were approximately $18.4 million.

As of December 31, 2007, the total gross costs recorded for obligations other than the purchase of homes, commercial properties, and related personal property claims, approximated $26.5 million. The Company has recorded as of December 31, 2007, total costs (net of anticipated insurance recoveries recorded of $21.4 million) associated with remediation and third party property damage claims resolution of approximately $23.5 million. The Company has not estimated or accrued for, because management does not believe it is probable that there will be any, potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from class action lawsuits related to the flood.

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 the Company will ultimately be required to pay. The costs and damages that the Company will ultimately pay may be greater than the amounts described and projected above. Such excess costs and damages could be material to the consolidated financial statements.

The Company is seeking insurance coverage for this release and for the ultimate costs for remediation, property damage claims, cleanup, resolution of class action lawsuits, and other claims brought by regulatory authorities. Although the Company believes that it will recover substantial sums under its environmental and liability insurance policies, the Company is not sure of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of the Company s claims. The difference between what the Company receives under its insurance policies compared to what has been recorded and described above could be material to the consolidated financial statements. The Company has received $10 million of insurance proceeds under its environmental insurance policy as of December 31, 2007.

As a result of the 2007 flood the refinery was not able to meet the annual average sulfur standard required in its hardship waiver. Management had provided timely notice to the EPA that the Company would not be able to meet the waiver requirement for 2007. Ordinarily, a refiner would purchase sulfur credits to meet the standard requirement. However, the Company s hardship waiver does not allow sulfur credits to be used in 2006 and 2007. The Company has been working with the EPA to resolve the matter. In anticipation of settlement, the refinery purchased $3.6 million worth of sulfur credits that would equal the amount of sulfur by which the Company exceeded the limit imposed by the hardship waiver. The Company will either use the credits by applying them towards its gasoline pool account or it will permanently retire the credits as part of the settlement. Because of the extraordinary nature of the 2007 flood, management does not anticipate the imposition of fines or penalties to resolve this matter.

Environmental, Health, and Safety (EHS) Matters

CVR is subject to various stringent federal, state, and local EHS rules and regulations. Liabilities related to EHS matters are recognized when the related costs are 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 EHS liabilities, no offset is made for potential recoveries. Such liabilities include estimates of CVR s share of costs attributable to potentially responsible parties which are

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

insolvent or otherwise unable to pay. All liabilities are monitored and adjusted regularly as new facts emerge or changes in law or technology occur.

CVR owns and/or operates manufacturing and ancillary operations at various locations directly related to petroleum refining and distribution and nitrogen fertilizer manufacturing. Therefore, CVR has exposure to potential EHS liabilities related to past and present EHS conditions at some of these locations.

Through an Administrative Order issued to Original Predecessor under the Resource Conservation and Recovery Act, as amended (RCRA), CVR is a potential party responsible for conducting corrective actions at its Coffeyville, Kansas and Phillipsburg, Kansas facilities. In 2005, CRNF agreed to participate in the State of Kansas Voluntary Cleanup and Property Redevelopment Program (VCPRP) to address a reported release of urea ammonium nitrate (UAN) at the Coffeyville UAN loading rack. As of December 31, 2006 and December 31, 2007, environmental accruals of $7,222,754 and $7,646,313, respectively, were reflected in the consolidated balance sheets for probable and estimated costs for remediation of environmental contamination under the RCRA Administrative Order and the VCPRP, including amounts totaling $1,827,649 and $2,802,000, respectively, included in other current liabilities. The Successor accruals were determined based on an estimate of payment costs through 2033, which scope of remediation was arranged with the EPA and are discounted at the appropriate risk free rates at December 31, 2006 and December 31, 2007, respectively. The accruals include estimated closure and post-closure costs of $1,857,000 and $1,549,000 for two landfills at December 31, 2006 and December 31, 2007, respectively. The estimated future payments for these required obligations are as follows (in thousands):

Year Ending December 31,	**Amount**
2008	$ 2,802
2009	687
2010	1,556
2011	313
2012	313
Thereafter	3,282
Undiscounted total	8,953
Less amounts representing interest at 3.90%	1,307
Accrued environmental liabilities at December 31, 2007	$ 7,646

Management periodically reviews and, as appropriate, revises its environmental accruals. Based on current information and regulatory requirements, management believes that the accruals established for environmental expenditures are adequate.

The EPA has issued regulations intended to limit amounts of sulfur in diesel and gasoline. The EPA has granted petition for a technical hardship waiver with respect to the date for compliance in meeting the sulfur-lowering standards. Immediate Predecessor and Successor spent approximately $27 million in 2005, $79 million in 2006, and

$17 million in 2007, and based on information currently available, CVR anticipates spending approximately $29 million in 2008, $11 million in 2009, and $6 million in 2010 to comply with the low-sulfur rules. The entire amounts are expected to be capitalized.

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. 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 December 31, 2007 capital expenditures were approximately $6,065,713, $20,165,483, $144,793,610, and $122,341,104, respectively, and were incurred to improve the environmental compliance and efficiency of the operations.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CVR believes it is in substantial compliance with existing EHS rules and regulations. There can be no assurance that the EHS matters described above or other EHS matters which may develop in the future will not have a material adverse effect on the business, financial condition, or results of operations.

(15) Derivative Financial Instruments

Gain (loss) on derivatives consisted of the following:

	Predecessor	Successor		
	174 Days Ended June 23, 2005	174 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Realized loss on swap agreements	$	$ (59,300,670)	$ (46,768,651)	$ (157,238,799)
Unrealized gain (loss) on swap agreements		(235,851,568)	126,771,145	(103,211,660)
Loss on termination of swap		(25,000,000)		
Realized gain (loss) on other agreements	(7,664,725)	(1,867,513)	8,361,050	(15,346,204)
Unrealized gain (loss) on other agreements		(1,697,640)	2,411,340	(1,348,064)
Realized gain (loss) on interest rate swap agreements		(103,731)	4,398,164	4,115,272
Unrealized gain (loss) on interest rate swap agreements		7,759,011	(679,908)	(8,948,640)
Total gain (loss) on derivatives	$ (7,664,725)	$ (316,062,111)	$ 94,493,140	$ (281,978,095)

CVR is subject to price fluctuations caused by supply conditions, weather, economic conditions, and other factors and to interest rate fluctuations. To manage price risk on crude oil and other inventories and to fix margins on certain future production, the Company may enter into various derivative transactions. In addition, the Successor, as further described below, entered into certain commodity derivate contracts and an interest rate swap as required by the long-term debt agreements.

CVR has adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* which imposes extensive record-keeping requirements in order to designate a derivative financial instrument as a hedge. CVR holds derivative instruments, such as exchange-traded crude oil futures, certain over-the-counter forward swap agreements, and interest rate swap agreements, which it believes provide an economic hedge on future transactions, but such instruments are not designated as hedges. Gains or losses related to the change in fair value and periodic settlements of these derivative instruments are classified as gain (loss) on derivatives.

At December 31, 2007, CVR s Petroleum Segment held commodity derivative contracts (swap agreements) for the period from July 1, 2005 to June 30, 2010 with a related party (see note 16). The swap agreements were originally executed on June 16, 2005 in conjunction with the Acquisition of the Immediate Predecessor and required under the terms of the long-term debt agreements. The notional quantities on the date of execution were 100,911,000 barrels of crude oil; 2,348,802,750 gallons of unleaded gasoline and 1,889,459,250 gallons of heating oil. The swap agreements were executed at the prevailing market rate at the time of execution and Management believes the swap agreements provide an economic hedge on future transactions. At December 31, 2007 the notional open amounts under the swap agreements were 42,309,750 barrels of crude oil; 888,504,750 gallons of unleaded gasoline and 888,504,750 gallons of heating oil. These positions resulted in unrealized gains (losses) for the 233-day period ended December 31, 2005 and the years ended December 31, 2006 and December 31, 2007 of $(235,851,568), $126,771,145 and $(103,211,660), respectively, using a valuation method that utilizes quoted market prices and assumptions for the estimated forward yield curves of the related commodities in periods when quoted market prices are unavailable. The Petroleum Segment recorded $(59,300,670), $(46,768,651) and $(157,238,799) in realized

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(losses) on these swap agreements for the 233-day period ended December 31, 2005, and the years ended December 31, 2006 and December 31, 2007, respectively.

Successor entered certain crude oil, heating oil, and gasoline option agreements with a related party (see notes 1 and 16) 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 gain (loss) on derivatives for the 233 days ended December 31, 2005.

The Petroleum Segment also recorded mark-to-market net gains (losses), exclusive of the swap agreements described above and the interest rate swaps described in the following paragraph, in gain (loss) on derivatives of $(7,664,725), $(3,565,153), $10,772,391, and $(16,694,268) for the 174-day period ended June 23, 2005, the 233-day period ended December 31, 2005, the years ended December 31, 2006, and December 31, 2007, respectively. All of the activity related to the commodity derivative contracts is reported in the Petroleum Segment.

At December 31, 2007, CVR held derivative contracts known as interest rate swap agreements that converted Successor s floating-rate bank debt (see note 11) into 4.195% fixed-rate debt on a notional amount of $375,000,000. Half of the agreements are held with a related party (as described in note 16), and the other half are held with a financial institution that is a lender under CVR s long-term debt agreements. The swap agreements carry the following terms:

Period Covered	Notional Amount	Fixed Interest Rate
June 30, 2007 to March 31, 2008	325 million	4.195%
March 31, 2008 to March 31, 2009	250 million	4.195%
March 31, 2009 to March 31, 2010	180 million	4.195%
March 31, 2010 to June 30, 2010	110 million	4.195%

CVR pays the fixed rates listed above and receives a floating rate based on three-month LIBOR rates, with payments calculated on the notional amounts listed above. The notional amounts do not represent actual amounts exchanged by the parties but instead represent the amounts on which the contracts are based. The swap is settled quarterly and marked to market at each reporting date, and all unrealized gains and losses are currently recognized in income. Transactions related to the interest rate swap agreements were not allocated to the Petroleum or Nitrogen Fertilizer segments. Mark-to-market net gains (losses) on derivatives and quarterly settlements were $7,655,280, $3,718,256 and $(4,833,368) for the 233-day period ended December 31, 2005 and the years ended December 31, 2006 and December 31, 2007, respectively.

(16) Related Party Transactions

Pegasus Partners II, L.P. (Pegasus) was a majority owner of Immediate Predecessor.

On March 3, 2004, Immediate Predecessor entered into a services agreement with an affiliate company of Pegasus, Pegasus Capital Advisors, L.P. (Affiliate) pursuant to which Affiliate provided Immediate Predecessor with managerial and advisory services. An amount totaling approximately $1,000,000 relating to the agreement were expensed in selling, general, and administrative expenses (exclusive of depreciation and amortization) for the 174 days ended June 23, 2005.

GS Capital Partners V Fund, L.P. and related entities (GS or Goldman Sachs Funds) and Kelso Investment Associates VII, L.P. and related entity (Kelso or Kelso Funds) are majority owners of CVR.

CVR paid companies related to GS and Kelso each equal amounts totaling $6.0 million for transaction fees related to the Acquisition, as well as an additional $0.7 million paid to GS for reimbursed expenses related to the Acquisition. These expenditures were included in the cost of the Acquisition referred to in note 1.

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

An affiliate of GS is one of the lenders in conjunction with the financing of the Acquisition. The Company paid this affiliate of GS a $22.1 million fee included in deferred financing costs. For the 233 days ended December 31, 2005, Successor made interest payments of $1.8 million recorded in interest expense and other financial costs and paid letter of credit fees of approximately $155,000 recorded in selling, general, and administrative expenses (exclusive of depreciation and amortization), to this affiliate of GS. Additionally, a fee in the amount of $125,000 was paid to this affiliate of GS for assistance with modification of the credit facility in June 2006.

An affiliate of GS is one of the lenders in conjunction with the refinancing that occurred on December 28, 2006. The Company paid this affiliate of GS a $8,062,500 million fee and expense reimbursements of $78,243 included in deferred financing costs.

On June 24, 2005, CALLC entered into management services agreements with each of GS and Kelso pursuant to which GS and Kelso agreed to provide CALLC with managerial and advisory services. In consideration for these services, an annual fee of $1.0 million each was paid to GS and Kelso, plus reimbursement for any out-of-pocket expenses. The agreements had a term ending on the date GS and Kelso ceased to own any interests in CALLC. Relating to the agreements, $1,310,416, $2,315,937 and $1,703,990 were expensed in selling, general, and administrative expenses (exclusive of depreciation and amortization) for the 233 days ended December 31, 2005, and the years ended December 31, 2006 and December 31, 2007, respectively. The agreements terminated upon consummation of CVR s initial public offering on October 26, 2007. The Company paid a one-time fee of $5 million to each of GS and Kelso by reason of such termination on October 26, 2007.

CALLC entered into certain crude oil, heating oil, and gasoline swap agreements with a subsidiary of GS. The original swap agreements were entered into on May 16, 2005 (as described in note 1) and were terminated on June 16, 2005, resulting in a $25 million loss on termination of swap agreements for the 233 days ended December 31, 2005. Additional swap agreements with this subsidiary of GS were entered into on June 16, 2005, with an expiration date of June 30, 2010 (as described in note 15). Amounts totaling $(297,010,762), $80,002,494, and $(260,450,459) were reflected in gain (loss) on derivatives related to these swap agreements for the 233 days ended December 31, 2005, and the years ended December 31, 2006 and December 31, 2007, respectively. In addition, the consolidated balance sheet at December 31, 2006 and December 31, 2007 includes liabilities of $36,894,802 and $262,414,874 included in current payable to swap counterparty and $72,806,486 and $88,230,110 included in long-term payable to swap counterparty, respectively.

On June 26, 2007, the Company entered into a letter agreement with the subsidiary of GS to defer a $45.0 million payment owed on July 8, 2007 to the GS subsidiary for the period ended September 30, 2007 until August 7, 2007. Interest accrued on the deferred amount of $45.0 million at the rate of LIBOR plus 3.25%.

As a result of the flood and the related temporary cessation of business operations, the Company entered into a subsequent letter agreement on July 11, 2007 in which the GS subsidiary agreed to defer an additional $43.7 million of the balance owed for the period ending June 30, 2007. This deferral was entered into on the conditions that each of GS and Kelso each agreed to guarantee one half of the payment and that 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, the Company entered into a letter agreement in which the GS subsidiary agreed to defer to September 7, 2007 both the $45.0 million payment due August 7, 2007 along with accrued interest and the

$43.7 million payment due July 25, 2007 with the related accrued interest. These payments were deferred on the conditions that GS and Kelso each agreed to guarantee one half of the payments. Additionally, interest accrues on the amount from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, the Company entered into an additional letter agreement in which the GS subsidiary agreed to further defer both deferred payment amounts and the related accrued interest with payment being

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

due on January 31, 2008. Additionally, it was further agreed that the $35 million payment to settle hedged volumes through August 15, 2007 would be deferred with payment being due on January 31, 2008. Interest accrues on all deferral amounts through the payment due date at LIBOR plus 1.50%. GS and Kelso have each agreed to guarantee one half of all payment deferrals. The GS Subsidiary further agreed to defer these payment amounts to August 31, 2008 if the Company closed an initial public offering prior to January 31, 2008. Due to the consummation of the initial public offering on October 26, 2007, these payment amounts are now deferred until August 31, 2008; however, the company is required to use 37.5% of its consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferral amounts.

These deferred payment amounts are included in the consolidated balance sheet at December 31, 2007 in current payable to swap counterparty. Interest relating to the deferred payment amounts reflected in interest expense and other financial costs for the year ended December 31, 2007 was $3,625,047. $3,625,047 is also included in other current liabilities at December 31, 2007.

On June 30, 2005, CVR entered into three interest-rate swap agreements with the same subsidiary of GS (as described in note 15). Amounts totaling $3,826,342, $1,857,801, and $(2,404,755) were recognized related to these swap agreements for the 233 days ended December 31, 2005, and the years ended December 31, 2006 and December 31, 2007, respectively, and are reflected in gain (loss) on derivatives. In addition, the consolidated balance sheet at December 31, 2006 and December 31, 2007 includes $1,533,738 and $0 in prepaid expenses and other current assets, $2,014,504 and $0 in other long-term assets, $0 and $371,184 in other current liabilities and $0 and $556,775 in other long-term liabilities related to the same agreements, respectively.

Effective December 30, 2005, CVR entered into a crude oil supply agreement with a subsidiary of GS (Supplier). Both parties will negotiate the cost of each barrel of crude oil to be purchased from a third party. CVR will pay Supplier a fixed supply service fee per barrel over the negotiated cost of each barrel of crude purchased. The cost is adjusted further using a spread adjustment calculation based on the time period the crude oil is estimated to be delivered to the refinery, other market conditions, and other factors deemed appropriate. The monthly spread quantity for any delivery month at any time shall not exceed approximately 3.1 million barrels. The initial term of the agreement was to December 31, 2006. CVR and Supplier agreed to extend the term of the Supply Agreement for an additional 12 month period, January 1, 2007 through December 31, 2007 and in connection with the extension amended certain terms and conditions of the Supply Agreement. On December 31, 2007, CVR and supplier entered into an amended and restated crude oil supply agreement. The terms of the agreement remained substantially the same. $1,622,824 and $360,177 were recorded on the consolidated balance sheet at December 31, 2006 and December 31, 2007, respectively, in prepaid expenses and other current assets for prepayment of crude oil. In addition, $31,750,784 and $42,777,684 were recorded in inventory and $13,458,977 and $19,583,149 were recorded in accounts payable at December 31, 2006 and December 31, 2007, respectively. Expenses associated with this agreement, included in cost of product sold (exclusive of depreciated and amortization) for the years ended December 31, 2006 and December 31, 2007 totaled $1,591,120,148 and $1,459,595,068, respectively. Interest expense associated with this agreement for the years ended December 31, 2006 and December 31, 2007 totaled $0 and $(375,537), respectively.

The Company had a note receivable with an executive member of management. During the period ended December 31, 2006, the board of directors approved to forgive the note receivable and related accrued interest receivable. The balance of the note receivable forgiven was $350,000. Accrued interest receivable forgiven was approximately $17,989. The total amount was charged to compensation expense.

On August 23, 2007, the Company entered into three new credit facilities, consisting of a $25 million secured facility, a $25 million unsecured facility and a $75 million unsecured facility. A subsidiary of GS was the sole lead arranger and sole bookrunner for each of these new credit facilities. These credit facilities and their arrangements are more fully described in Note 11, Long-Term Debt . The Company paid the subsidiary

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of GS a $1.3 million fee included in deferred financing costs. For the year ended December 31, 2007, interest expenses relating to these agreements were $866,745. The secured and unsecured facilities were paid in full on October 26, 2007 with proceeds from CVR s initial public offering, see Note 1, Organization and History of Company , and both facilities terminated. Additionally, in connection with the consummation of the initial public offering, the $75 million unsecured facility also terminated.

As a result of the refinery turnaround in early 2007, CVR needed to delay the processing of quantities of crude oil that it purchased from various small independent producers. In order to facilitate this anticipated delay, CVR entered into a purchase, storage and sale agreement for gathered crude oil, dated March 20, 2007, with J. Aron, a subsidiary of GS. Pursuant to the terms of the agreement, J. Aron agreed to purchase gathered crude oil from CVR, store the gathered crude oil and sell CVR the gathered crude oil on a forward basis. As of December 31, 2007, there were no longer any open commitments with regard to the agreement. Interest expense associated with this agreement included in interest expense and other financing costs was $195,663.

Goldman, Sachs & Co. was the lead underwriter of CVR s initial public offering in October 2007. As lead underwriter, they were paid a customary underwriting discount of approximately $14.7 million, which includes $0.7 million of expense reimbursement.

On October 24, 2007, CVR paid a cash dividend, to its shareholders, including approximately $5.23 million that was ultimately distributed from CALLC II (Goldman Sachs Funds) and approximately $5.15 million distributed from CALLC to the Kelso Funds. Management collectively received approximately $0.13 million.

(17) Business Segments

CVR measures segment profit as operating income for Petroleum and Nitrogen Fertilizer, CVR s two reporting segments, based on the definitions provided in SFAS No. 131, *Disclosures About Segments of an Enterprise and Related Information*. All operations of the segments are located in the United States.

CVR changed its corporate selling, general and administrative allocation method 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.

Petroleum

Principal products of the Petroleum Segment are refined fuels, propane, and petroleum refining by-products including coke. CVR uses the coke in the manufacture of nitrogen fertilizer at the adjacent nitrogen fertilizer plant. (For CVR, a $15-per-ton transfer price is used to record intercompany sales on the part of the Petroleum Segment and corresponding intercompany cost of product sold (exclusive of depreciation and amortization) for the Nitrogen Fertilizer Segment through October 24, 2007.) After October 24, 2007, intercompany sales are recorded according to the interconnect agreement (see note 1). The intercompany transactions are eliminated in the Other Segment. Intercompany sales included in Petroleum net sales were $2,444,565, $2,782,455, $5,339,715, and $5,195,105 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 December 31, 2007, respectively.

Nitrogen Fertilizer

The principal product of the Nitrogen Fertilizer Segment is nitrogen fertilizer. Intercompany cost of product sold (exclusive of depreciation and amortization) for the coke transfer described above was $2,778,079, $2,574,908, $5,241,927, and $4,527,763 for the 174-day period ended June 23, 2005, the 233-day

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

period ended December 31, 2005, and the years ended December 31, 2006, and December 31, 2007, respectively.

Other Segment

The Other Segment reflects intercompany eliminations, cash and cash equivalents, all debt related activities, income tax activities and other corporate activities that are not allocated to the operating segments.

	Predecessor	Successor		
	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Net sales				
Petroleum	$ 903,802,983	$ 1,363,390,142	$ 2,880,442,544	$ 2,806,204,271
Nitrogen Fertilizer	79,347,843	93,651,855	162,464,533	165,855,287
Other				
Intersegment elimination	(2,444,565)	(2,782,455)	(5,339,715)	(5,195,105)
Total	$ 980,706,261	$ 1,454,259,542	$ 3,037,567,362	$ 2,966,864,453
Cost of product sold (exclusive of depreciation and amortization)				
Petroleum	$ 761,719,405	$ 1,156,208,301	$ 2,422,717,768	$ 2,282,554,819
Nitrogen Fertilizer	9,125,852	14,503,824	25,898,902	13,041,955
Other				
Intersegment elimination	(2,778,079)	(2,574,908)	(5,241,927)	(4,527,763)
Total	$ 768,067,178	$ 1,168,137,217	$ 2,443,374,743	$ 2,291,069,011
Direct operating expenses (exclusive of depreciation and amortization)				
Petroleum	$ 52,611,148	$ 56,159,473	$ 135,296,759	$ 209,473,936
Nitrogen Fertilizer	$ 28,302,714	29,153,729	63,683,224	66,662,894
Other				
Total	$ 80,913,862	$ 85,313,202	$ 198,979,983	$ 276,136,830
Net costs associated with flood				
Petroleum	$	$	$	$ 36,668,619
Nitrogen Fertilizer				2,431,957
Other				2,422,690

Total	$	$	$	$ 41,523,266
Depreciation and amortization				
Petroleum	$ 770,728	$ 15,566,987	$ 33,016,619	$ 43,040,267
Nitrogen Fertilizer	316,446	8,360,911	17,125,897	16,819,147
Other	40,831	26,133	862,066	919,761
Total	$ 1,128,005	$ 23,954,031	$ 51,004,582	$ 60,779,175
Operating income (loss)				
Petroleum	$ 76,654,428	$ 123,044,854	$ 245,577,550	$ 162,547,830
Nitrogen Fertilizer	35,267,752	35,731,056	36,842,252	46,592,747
Other	333,514	(240,848)	(811,869)	(4,906,161)
Total	$ 112,255,694	$ 158,535,062	$ 281,607,933	$ 204,234,416
Capital expenditures				
Petroleum	$ 10,790,042	$ 42,107,751	$ 223,553,105	$ 261,561,642
Nitrogen fertilizer	1,434,921	2,017,385	13,257,681	6,487,455
Other	31,830	1,046,998	3,414,606	543,442
Total	$ 12,256,793	$ 45,172,134	$ 240,225,392	$ 268,592,539

Table of Contents

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Predecessor	Successor		
	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Total assets				
Petroleum			$ 907,314,951	$ 1,271,712,398
Nitrogen Fertilizer			417,657,093	446,762,980
Other			124,507,471	137,592,713
Total			$ 1,449,479,515	$ 1,856,068,091
Goodwill				
Petroleum			$ 42,806,422	$ 42,806,422
Nitrogen Fertilizer			40,968,463	40,968,463
Other				
Total			$ 83,774,885	$ 83,774,885

(18) Major Customers and Suppliers

Sales to major customers were as follows:

	Predecessor	Successor		
	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Petroleum				
Customer A	17%	16%	2%	3%
Customer B	5%	6%	5%	5%
Customer C	17%	15%	15%	12%
Customer D	14%	17%	10%	7%
Customer E	11%	11%	10%	9%
Customer F	8%	7%	9%	10%
	72%	72%	51%	46%
Nitrogen Fertilizer				

Customer G	16%	10%	5%	3%
Customer H	9%	10%	7%	18%
	25%	20%	12%	21%

The Petroleum Segment maintains long-term contracts with one supplier for the purchase of its crude oil. The agreement with Supplier A expired in December 2005, at which time Successor entered into a similar arrangement with Supplier B, a related party (as described in note 16). Purchases contracted as a percentage of

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the total cost of product sold (exclusive of depreciation and amortization) for each of the periods were as follows:

	Predecessor	Successor		
	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Supplier A	82%	73%		
Supplier B			67%	64%
	82%	73%	67%	64%

The Nitrogen Fertilizer Segment maintains long-term contracts with one supplier. Purchases from this supplier as a percentage of direct operating expenses (exclusive of depreciation and amortization) were as follows:

	Predecessor	Successor		
	174 Days Ended June 23, 2005	233 Days Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Supplier	4%	5%	8%	5%

(19) Selected Quarterly Financial and Information (Unaudited)

Summarized quarterly financial data for the December 31, 2006 and 2007.

	Year Ended December 31, 2006 Quarter			
	First	Second	Third	Fourth
Net sales	669,727,347	880,839,282	778,586,242	708,414,491
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	539,538,749	663,910,456	644,627,352	595,298,186
Direct operating expenses (exclusive of depreciation and amortization)	44,287,963	43,477,747	56,695,517	54,518,757

Selling, general and administrative (exclusive of depreciation and amortization)	8,493,544	11,975,927	12,326,943	29,803,707
Net costs associated with flood				
Depreciation and amortization	12,003,797	12,018,311	12,787,536	14,194,938
Total operating costs and expenses	604,324,053	731,382,441	726,437,348	693,815,588
Operating income (loss)	65,403,294	149,456,841	52,148,894	14,598,903

167

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2006 Quarter			
	First	Second	Third	Fourth
Other income (expense):				
Interest expense and other financing costs	(12,206,618)	(10,129,002)	(10,681,064)	(10,862,960)
Interest income	590,075	1,093,082	1,090,792	676,241
Gain (loss) on derivatives	(17,615,311)	(108,846,732)	171,208,895	49,746,289
Loss on extinguishment of debt				(23,360,306)
Other income (expense)	57,614	(320,478)	573,569	(1,210,535)
Total other income (expense)	(29,174,240)	(118,203,130)	162,192,192	14,988,729
Income before income taxes and minority interest	36,229,054	31,253,711	214,341,086	29,587,632
Income tax expense (benefit)	14,106,160	11,619,396	85,302,273	8,812,331
Minority interest in (income) loss of subsidiaries				
Net income	22,122,894	19,634,315	129,038,813	20,775,301
Unaudited Pro Forma Information (note 12)				
Net earnings per share				
Basic	$ 0.26	$ 0.23	$ 1.50	$ 0.24
Diluted	$ 0.26	$ 0.23	$ 1.50	$ 0.24
Weighted average common shares outstanding				
Basic	86,141,291	86,141,291	86,141,291	86,141,291
Diluted	86,158,791	86,158,791	86,158,791	86,158,791

Quarterly Financial Information (Unaudited)

	Year Ended December 31, 2007 Quarter			
	First	Second	Third	Fourth
Net sales	390,482,819	843,413,093	585,977,758	1,146,990,783
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	303,670,229	569,623,094	446,169,603	971,606,085

Direct operating expenses (exclusive of depreciation and amortization)	113,411,569	60,954,515	44,440,204	57,330,542
Selling, general and administrative (exclusive of depreciation and amortization)	13,149,892	14,937,401	14,034,765	50,999,697
Net costs associated with flood		2,138,942	32,192,342	7,191,982
Depreciation and amortization	14,235,431	17,957,027	10,481,065	18,105,652
Total operating costs and expenses	444,467,121	665,610,979	547,317,979	1,105,233,958

168

Table of Contents

	Year Ended December 31, 2007 Quarter First	Second	Third	Fourth
Operating income (loss)	(53,984,302)	177,802,114	38,659,779	41,756,825
Other income (expense):				
Interest expense and other financing costs	(11,856,624)	(15,762,799)	(18,339,731)	(15,167,029)
Interest income	451,984	161,332	150,610	335,645
Gain (loss) on derivatives	(136,959,221)	(155,485,213)	40,532,495	(30,066,156)
Loss on extinguishment of debt				(1,257,764)
Other income (expense)	764	101,470	52,393	201,181
Total other income (expense)	(148,363,097)	(170,985,210)	22,395,767	(45,954,123)
Income (loss) before income taxes and minority interest	(202,347,399)	6,816,904	61,055,546	(4,197,298)
Income tax expense (benefit)	(47,297,700)	(93,668,582)	47,609,671	11,718,001
Minority interest in (income) loss of subsidiaries	675,747	(418,999)	(46,686)	
Net income (loss)	(154,373,952)	100,066,487	13,399,189	(15,915,299)
Unaudited Pro Forma Information (note 12)				
Net earnings (loss) per share				
Basic	$ (1.79)	$ 1.16	$ 0.16	$ (0.18)
Diluted	$ (1.79)	$ 1.16	$ 0.16	$ (0.18)
Weighted average common shares outstanding				
Basic	86,141,291	86,141,291	86,141,291	86,141,291
Diluted	86,141,291	86,158,791	86,158,791	86,141,291

169

Table of Contents

Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation was carried out by the Company s management, with the participation of the Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures were effective as of the end of the period covered by this report. In addition, no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management s Assessment of Internal Controls. This annual report does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm regarding internal control over financial reporting due to a transition period established by rules of the SEC for newly public companies. We will be required to include management s report on our internal control over financial reporting and the attestation report of our registered public accounting firm in our annual report on Form 10-K for the fiscal year ending December 31, 2008.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Information required by this Item regarding our directors and corporate governance is included under the captions Corporate Governance, Proposal 1 Election of Directors, Section 16(a) Beneficial Ownership Reporting Compliance, and Stockholder Proposals contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2008, and this information is incorporated herein by reference. Information required by this Item regarding our executive officers is included under the caption Executive Officers in Item 1 in Part I of this Report, and this information is incorporated herein by reference.

Item 11. ***Executive Compensation***

Information about executive and director compensation is included under the captions Corporate Governance Compensation Committee Interlocks and Insider Participation, Proposal 1 Election of Directors, Director Compensation for 2007, Compensation Discussion and Analysis, Compensation Committee Report and Compensation of Executive Officers contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2008, and this information is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Information about security ownership of certain beneficial owners and management is included under the captions Compensation of Executive Officers Equity Compensation Plan Information and Securities Ownership of Certain Beneficial Owners and Officers and Directors contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2008, and this information is incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Information about related party transactions between CVR Energy (and its predecessors) and its directors, executive officers and 5% stockholders that occurred during the year ended December 31, 2007 is included under the captions Certain Relationships and Related Party Transactions and Corporate Governance The Controlled Company Exemption and Director Independence Director Independence contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2008, and this information is incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services*

Information about principal accounting fees and services is included under the captions Proposal 2 Ratification of Selection of Independent Registered Public Accounting Firm and Fees Paid to the Independent Registered Public Accounting Firm contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2008, and this information is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) Financial Statements

See Index to Consolidated Financial Statements.

(a)(2) Financial Statement Schedules

All schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and therefore have been omitted.

(a)(3) Exhibits

Exhibit Number	Exhibit Title
3.1**	Amended and Restated Certificate of Incorporation of CVR Energy, Inc. (filed as Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).
3.2**	Amended and Restated Bylaws of CVR Energy, Inc. (filed as Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).
4.1**	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.1**	Second Amended and Restated Credit and Guaranty Agreement, dated as of December 28, 2006, among Coffeyville Resources, LLC and the other parties thereto (filed as Exhibit&#16