CVR ENERGY INC
Form 10-K
March 12, 2010

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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, 2009

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	**77479**
Sugar Land, Texas	*(Zip Code)*
(Address of Principal Executive Offices)	

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, $0.01 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 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 for 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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 or Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o 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. o

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

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

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 aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant computed based on the New York Stock Exchange closing price on June 30, 2009 (the last day of the registrant s second fiscal quarter) was $168,686,023.

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 10, 2010
Common Stock, par value $0.01 per share	86,329,237 shares

Documents Incorporated By Reference

Document	Parts Incorporated
Proxy Statement for the 2010 Annual Meeting of Stockholders to be held May 19, 2010	Items 9, 10, 11, 12 and 13 of Part III

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GLOSSARY OF SELECTED TERMS

The following are definitions of certain industry terms used in this Form 10-K.

2-1-1 crack spread The approximate gross margin resulting from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of distillate. The 2-1-1 crack spread is expressed in dollars per barrel.

Ammonia Ammonia is a direct application fertilizer and is primarily used as a building block for other nitrogen products for industrial applications and finished fertilizer products.

Backwardation market Market situation in which futures prices are lower in succeeding delivery months. Also known as an inverted market. The opposite of contango.

Barrel Common unit of measure in the oil industry which equates to 42 gallons.

Blendstocks Various compounds that are combined with gasoline or diesel from the crude oil refining process to make finished gasoline and diesel fuel; these may include natural gasoline, fluid catalytic cracking unit or FCCU gasoline, ethanol, reformate or butane, among others.

bpd Abbreviation for barrels per day.

Bulk sales Volume sales through third party pipelines, in contrast to tanker truck quantity sales.

Capacity Capacity is defined as the throughput a process unit is capable of sustaining, either on a calendar or stream day basis. The throughput may be expressed in terms of maximum sustainable, nameplate or economic capacity. The maximum sustainable or nameplate capacities may not be the most economical. The economic capacity is the throughput that generally provides the greatest economic benefit based on considerations such as feedstock costs, product values and downstream unit constraints.

Catalyst A substance that alters, accelerates, or instigates chemical changes, but is neither produced, consumed nor altered in the process.

Coker unit A refinery unit that utilizes the lowest value component of crude oil remaining after all higher value products are removed, further breaks down the component into more valuable products and converts the rest into pet coke.

Common units The class of interests issued under the limited liability company agreements governing Coffeyville Acquisition LLC, Coffeyville Acquisition II LLC and Coffeyville Acquisition III LLC, which provide for voting rights and have rights with respect to profits and losses of, and distributions from, the respective limited liability companies.

Contango market Markets that are characterized by prices for future delivery that are higher than the current or spot price of the commodity.

Corn belt The primary corn producing region of the United States, which includes Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Ohio and Wisconsin.

Crack spread A simplified calculation that measures the difference between the price for light products and crude oil. For example, the 2-1-1 crack spread is often referenced and represents the approximate gross margin resulting

from processing two barrels of crude oil to produce one barrel of gasoline and one barrel of distillate.

Distillates Primarily diesel fuel, kerosene and jet fuel.

Ethanol A clear, colorless, flammable oxygenated hydrocarbon. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. It is used in the United States as a gasoline octane enhancer and oxygenate.

Farm belt Refers to the states of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas and Wisconsin.

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Feedstocks Petroleum products, such as crude oil and natural gas liquids, that are processed and blended into refined products.

Heavy crude oil A relatively inexpensive crude oil characterized by high relative density and viscosity. Heavy crude oils require greater levels of processing to produce high value products such as gasoline and diesel fuel.

Independent petroleum refiner A refiner that does not have crude oil exploration or production operations. An independent refiner purchases the crude oil used as feedstock in its refinery operations from third parties.

Light crude oil A relatively expensive crude oil characterized by low relative density and viscosity. Light crude oils require lower levels of processing to produce high value products such as gasoline and diesel fuel.

Magellan Magellan Midstream Partners L.P., a publicly traded company whose business is the transportation, storage and distribution of refined petroleum products.

MMBtu One million British thermal units or Btu: a measure of energy. One Btu of heat is required to raise the temperature of one pound of water one degree Fahrenheit.

Natural gas liquids Natural gas liquids, often referred to as NGLs, are both feedstocks used in the manufacture of refined fuels and are products of the refining process. Common NGLs used include propane, isobutane, normal butane and natural gasoline.

PADD II Midwest Petroleum Area for Defense District which includes Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, and Wisconsin.

Petroleum coke (Pet coke) A coal-like substance that is produced during the refining process.

Refined products Petroleum products, such as gasoline, diesel fuel and jet fuel, that are produced by a refinery.

Sour crude oil A crude oil that is relatively high in sulfur content, requiring additional processing to remove the sulfur. Sour crude oil is typically less expensive than sweet crude oil.

Spot market A market in which commodities are bought and sold for cash and delivered immediately.

Sweet crude oil A crude oil that is relatively low in sulfur content, requiring less processing to remove the sulfur. Sweet crude oil is typically more expensive than sour crude oil.

Throughput The volume processed through a unit or a refinery.

Turnaround A periodically required standard procedure to refurbish and maintain a refinery that involves the shutdown and inspection of major processing units and occurs every three to four years.

UAN A solution of urea and ammonium nitrate in water used as a fertilizer.

Wheat belt The primary wheat producing region of the United States, which includes Oklahoma, Kansas, North Dakota, South Dakota and Texas.

WTI West Texas Intermediate crude oil, a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a

benchmark for other crude oils.

WTS West Texas Sour crude oil, a relatively light, sour crude oil characterized by an API gravity of 30-32 degrees and a sulfur content of approximately 2.0 weight percent.

Yield The percentage of refined products that is produced from crude oil and other feedstocks.

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PART I

Item 1. *Business*

CVR Energy, Inc. and, unless the context otherwise requires, its subsidiaries (CVR Energy , the Company , we , us , o our) is an independent petroleum 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 CVR Partners, LP (the Partnership), a limited partnership which produces nitrogen fertilizers in the form of ammonia and UAN.

Our petroleum business includes a 115,000 bpd complex full coking medium-sour crude oil refinery in Coffeyville, Kansas. In addition to the refinery, we own and operate supporting businesses that include:

- a crude oil gathering system serving Kansas, Oklahoma, western Missouri, eastern Colorado and southwestern Nebraska;
- a 145,000 bpd pipeline system that transports crude oil to our refinery with 1.2 million barrels of associated company-owned storage tanks and an additional 2.7 million barrels of leased storage capacity located at Cushing, Oklahoma;
- 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 and NuStar Energy, LP (NuStar); and
- storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas.

The nitrogen fertilizer business consists of a nitrogen fertilizer plant in Coffeyville, Kansas that includes two pet coke gasifiers. The nitrogen fertilizer manufacturing facility is comprised of (1) a 1,225 ton-per-day ammonia unit, (2) a 2,025 ton-per-day UAN unit and (3) a dual train gasifier complex each with a capacity of 84 million standard cubic foot per day. The nitrogen fertilizer business is the only operation in North America that utilizes a pet 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, we believe the nitrogen fertilizer plant business is one of the lowest cost producers and marketers of ammonia and UAN fertilizers in North America.

We have two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2009, 2008 and 2007, we generated combined net sales of $3.1 billion, $5.0 billion and $3.0 billion, respectively, and operating income of $208.2 million, $148.7 million and $186.6 million, respectively. Our petroleum business generated $2.9 billion, $4.8 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 $170.2 million, $31.9 million and $144.9 million of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

Our History

Our refinery, which began operations in 1906, and the nitrogen fertilizer plant, built in 2000, were operated as components of Farmland Industries, Inc. (Farmland), an agricultural cooperative, and its predecessors until March 3, 2004.

Coffeyville Resources, LLC (CRLLC), a subsidiary of Coffeyville Group Holdings, LLC, won a bankruptcy court auction for Farmland s petroleum business and a nitrogen fertilizer plant located in Coffeyville, Kansas 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.

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On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC (CALLC), 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. CALLC 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 CALLC in order to consummate an initial public offering of the businesses operated by CALLC. Immediately prior to CVR Energy s initial public offering in October 2007:

- CALLC transferred all of its businesses to CVR Energy in exchange for all of CVR Energy s common stock;
- CALLC was effectively split into two entities, with the Kelso Funds controlling CALLC and the Goldman Sachs Funds controlling Coffeyville Acquisition II LLC (CALLC II) and CVR Energy s senior management receiving an equivalent position in each of the two entities;
- we transferred our nitrogen fertilizer business to the Partnership in exchange for all of the partnership interests in the Partnership; and
- we sold all of the interests of the managing general partner of the 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. CVR is a controlled company under the rules and regulations of the New York Stock Exchange (NYSE) where its shares are traded under the symbol CVI. At December 31, 2009, approximately 64% of CVR s outstanding shares were beneficially owned by the Goldman Sachs Funds (28%) and Kelso Funds (36%).

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Organizational Structure and Related Ownership as of December 31, 2009

The following chart illustrates our organizational structure and the organizational structure of the Partnership:

* CVR GP, LLC, which we refer to as Fertilizer GP, is the managing general partner of CVR Partners, LP. As managing general partner, Fertilizer GP holds incentive distribution rights, or IDRs, which entitle it to receive increasing percentages of the Partnership s quarterly distributions if the Partnership increases its distributions above an amount specified in the limited partnership agreement.

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Petroleum Business

We operate a 115,000 bpd complex full coking medium-sour crude oil refinery in Coffeyville, Kansas. Our refinery s production capacity represents approximately 15% 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.

For the year ended December 31, 2009, our refinery s product yield included gasoline (mainly regular unleaded) (52%), diesel fuel (primarily ultra low sulfur diesel) (39%), and pet coke and other refined products such as NGC (propane, butane), slurry, reformer feeds, sulfur, gas oil and produced fuel (9%).

Our petroleum business also includes the following auxiliary operating assets:

Crude Oil Gathering System. We own and operate a crude oil gathering system serving Kansas, Oklahoma, western Missouri, eastern Colorado and southwestern Nebraska. The system has field offices in Bartlesville, Oklahoma and Plainville and Winfield, Kansas. The system is comprised of approximately 300 miles of feeder and trunk pipelines, 71 trucks, and associated storage facilities for gathering sweet Kansas, Nebraska, Oklahoma, Missouri, and Colorado crude oils purchased from independent crude producers. We also lease a section of a pipeline from Magellan, which is incorporated into our crude oil gathering system. Our crude oil gathering system has a gathering capacity in excess of 30,000 bpd. Gathered crude oil provides a base supply of feedstock for our refinery and serves as an attractive and competitive supply of crude oil.

Phillipsburg Terminal. We own storage and terminalling facilities for refined fuels and asphalt in Phillipsburg, Kansas. The asphalt storage and terminalling facilities are used to receive, store and redeliver asphalt for another oil company for a fee pursuant to an asphalt services agreement.

Pipelines. We own a proprietary pipeline system capable of transporting approximately 145,000 bpd of 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 Pipeline L.P. (Plains). We also own associated crude oil storage tanks with a capacity of approximately 1.2 million barrels located outside our refinery.

Our refinery s complexity allows us to optimize the yields (the percentage of refined product that is produced from crude oil and other feedstocks) of higher value transportation fuels (gasoline and distillate). Complexity is a measure of a refinery s ability to process lower quality crude oil in an economic manner. As a result of key investments in our refining assets, our refinery s complexity score has increased to 12.2, and we have achieved significant increases in our refinery crude oil throughput rate over historical levels. Our higher complexity provides us the flexibility to increase our refining margin over comparable refiners with lower complexities.

Feedstocks Supply

Our refinery has the capability to process blends of a variety of crude oil ranging from heavy sour to light sweet crude oil. Currently, our refinery processes crude oil from a broad array of sources. We have access to foreign crude oil from Latin America, South America, West Africa, the Middle East, the North Sea and Canada. We purchase domestic crude oil from Kansas, Oklahoma, Nebraska, Texas, Colorado, North Dakota, Missouri, and offshore deepwater Gulf of Mexico production. While crude oil has historically constituted over 90% of our feedstock inputs during the last five years, other feedstock inputs include normal butane, natural gasoline, alky feed, naphtha, gas oil and vacuum tower bottoms.

Crude oil is supplied to our refinery through our wholly-owned gathering system and by pipeline. We have continued to increase the number of barrels of crude oil supplied through our crude oil gathering system in 2009 and now have the capacity of supplying in excess of 30,000 bpd of crude oil to the refinery. For 2009, the gathering system supplied approximately 25% of the refinery s crude oil demand. Locally produced crude oils are delivered to the refinery at a discount to WTI, and although slightly heavier and more sour, offer good

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economics to the refinery. These crude oils are light and sweet enough to allow us to blend higher percentages of lower cost crude oils such as heavy sour Canadian while maintaining our target medium sour blend with an API gravity of 28-36 degrees and 0.9-1.2% sulfur. Crude oils sourced outside of our proprietary gathering system are delivered to Cushing, Oklahoma by various pipelines including Seaway, Basin and Spearhead and subsequently to Coffeyville via the Plains pipeline and our own 145,000 bpd proprietary pipeline system.

For the year ended December 31, 2009, our crude oil supply blend was comprised of approximately 76% light sweet crude oil, 15% medium/light sour crude oil and 9% heavy sour crude oil. The light sweet crude oil includes our locally gathered crude oil.

For 2009, we obtained approximately 75% of the crude oil for our refinery, under a Crude Oil Supply Agreement effective December 31, 2008 (the Supply Agreement) with Vitol Inc. (Vitol). The Supply Agreement, whereby Vitol agreed to supply crude oil and intermediation logistics, had an initial term of two years. On July 7, 2009, we entered into an amendment to the Supply Agreement, which extended the initial term from two to three years ending December 31, 2011. Our crude oil intermediation agreement helps us reduce our inventory position and mitigate crude oil pricing risk.

Marketing and Distribution

We focus our petroleum product marketing efforts in the central mid-continent and Rocky Mountain areas because of their relative proximity to our refinery and their pipeline access. We engage in rack marketing, which is the supply of product through tanker trucks directly to customers located in close geographic proximity to our refinery and Phillipsburg terminal and to customers at throughput terminals on Magellan s and NuStar s refined products distribution systems. For the year ended December 31, 2009, approximately 31% of the refinery s products were sold through the rack system directly to retail and wholesale customers while the remaining 69% was sold through pipelines via bulk spot and term contracts. We make bulk sales (sales into third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Operating, L.P. (Enterprise) and NuStar.

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, 2009, QuikTrip Corporation accounted for 14% of our petroleum business sales and 68% of our petroleum sales were made to our ten largest customers. We sell bulk products based on industry market related indices such as Platts, Oil Price Information Service (OPIS) or at a spot market price based on a Group 3 differential to the New York Mercantile Exchange (NYMEX). Through our rack marketing division, the rack sales are at daily posted prices which are influenced by the NYMEX, competitor pricing and Group 3 spot market differentials.

Competition

Our petroleum business competes 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 cost of crude oil and other feedstock costs, refinery complexity, refinery efficiency, refinery product mix and product distribution and transportation costs. The location of our refinery provides us with a reliable supply of crude oil and a transportation cost advantage over our competitors. We primarily compete against seven refineries operated in the mid-continent region. In addition to these refineries, our oil refinery in Coffeyville, Kansas competes against trading companies, as well as 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, Conoco Phillips, Valero and Gary-Williams.

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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 winter agricultural work declines. 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 impact the 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 other nitrogen fertilizers.

Raw Material Supply

The nitrogen fertilizer facility s primary input is pet coke. During the past five years, approximately 74% 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 within a 60-mile radius of the nitrogen fertilizer plant.

Pet coke is produced as a by-product of the refinery s coker unit process. In order to refine heavy crude oils, which are lower in cost and more prevalent than higher quality crude oil, refiners use coker units which enables refiners to further upgrade heavy crude oil. In recent years, there has been a shift in North America from refining dwindling reserves of sweet crude oil to more readily available heavy and sour crude oil (which can be obtained from, among other places, the Canadian oil sands), which will result in increased pet coke production.

The nitrogen fertilizer business plant is located in Coffeyville, Kansas, which is part of the Midwest pet coke market. The Midwest pet coke market is not subject to the same level of pet coke price variability as is the Gulf Coast pet coke market. Given the fact that the majority of the nitrogen fertilizer business pet coke suppliers are located in the Midwest, the nitrogen fertilizer business geographic location gives it a significant freight cost advantage over its Gulf Coast pet coke market competitors. The Midwest Green Coke (Chicago Area, FOB Source) annual average price over the last three years has ranged from $12.17 to $27.00 per ton. The U.S. Gulf Coast market annual average price during the same period has ranged from $24.83 to $77.38 per ton.

Linde, Inc. (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 agreement with Linde expires in 2020.

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. Monthly charges and credits are recorded with steam valued at the natural gas price for the month.

Nitrogen Production and Plant Reliability

The nitrogen fertilizer plant was built in 2000 with two separate gasifiers to provide reliability. The plant uses a gasification process to convert pet coke to high purity hydrogen for subsequent conversion to ammonia. The nitrogen fertilizer plant is capable of processing approximately 1,400 tons per day of pet coke from our refinery and third-party sources and converting it into approximately 1,225 tons per day of ammonia. The nitrogen fertilizer plant is also capable of processing refinery produced hydrogen, as available, to produce up

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to an additional 130 tons of ammonia. A majority of the ammonia is converted to approximately 2,025 tons per day of UAN. Typically 0.41 tons of ammonia is required to produce one ton of UAN.

In order to maintain high on-stream factors, 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 its ammonia products to industrial and agricultural customers and the UAN products to agricultural customers. The demand for nitrogen fertilizer occurs during three key 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 smaller quantities of ammonia that are sold 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 a freight-on-board 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 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 four rail loading racks for each of ammonia and UAN, with an additional four rail loading racks for UAN.

The nitrogen fertilizer business markets agricultural products to destinations that produce the best margins for the business. The UAN market is primarily located near the Union Pacific Railroad lines or destinations that can be supplied by truck. The ammonia market is primarily located near the Burlington Northern Santa Fe or Kansas City Southern 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. 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. Based upon a three-year average, the nitrogen fertilizer business has sold approximately 85% of the ammonia it produces to agricultural customers primarily located in the mid-continent area between North Texas and Canada, and approximately 15% to industrial customers. Agricultural customers include distributors such as MFA, United Suppliers, Inc., Brandt Consolidated Inc., Gavilon Fertilizers LLC, Transammonia, Inc., Agri Services of Brunswick, LLC, Interchem, and

CHS Inc. Industrial customers include Tessenderlo Kerley, Inc., National Cooperative Refinery Association, and Dyno Nobel, Inc. 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.

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For the years ended December 31, 2009, 2008 and 2007, the top five ammonia customers in the aggregate represented 43.9%, 54.7% and 62.1% of the nitrogen fertilizer business ammonia sales, respectively, and the top five UAN customers in the aggregate represented 44.2%, 37.2% and 38.7% of the nitrogen fertilizer business UAN sales, respectively. During the year ended December 31, 2009, Brandt Consolidated Inc. accounted for 14.2% of the nitrogen fertilizer business ammonia sales, and Gavilon Fertilizers LLC accounted for 17.0% of the nitrogen fertilizer business UAN sales. During the year ended December 31, 2008, Brandt Consolidated Inc. accounted for 26.1% of the nitrogen fertilizer business ammonia sales, and Gavilon Fertilizers LLC accounted for 14.5% of the nitrogen fertilizer business UAN sales. During the year ended December 31, 2007, Brandt Consolidated Inc., MFA and Gavilon Fertilizers LLC accounted for 17.4%, 15.0% and 14.4% of the nitrogen fertilizer business ammonia sales, respectively, and Gavilon Fertilizers LLC 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.

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 2009 represented approximately 6.4% of the total U.S. demand and that the net ammonia produced and marketed at Coffeyville represented less than 1.0% 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, environmental and health and safety regulations governing the emission and release of hazardous substances into the environment, the treatment and discharge of waste water, the storage, handling, use and transportation of petroleum and nitrogen products, and the characteristics and composition of gasoline and diesel fuels. These laws, their underlying regulatory requirements and the enforcement thereof impact our petroleum business and operations and the nitrogen fertilizer business and operations 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.

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Our operations require numerous permits and authorizations. Failure to comply with these permits or environmental laws generally could result in fines, penalties or other sanctions or a revocation of our permits. In addition, environmental laws and regulations are often evolving and many of them have become more stringent or have become subject to more stringent interpretation or enforcement by federal or state agencies. Future environmental laws and regulations or more stringent interpretations of existing laws and regulations could result in increased capital, operating and compliance costs.

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 facilities to produce products that meet applicable requirements.

Air Emissions. The regulation of air emissions under the federal Clean Air Act requires us to obtain various construction and operating permits and to incur capital expenditures for the installation of certain air pollution control devices at our petroleum and nitrogen fertilizer operations. Various regulations specific to our operations have been implemented, such as National Emission Standard for Hazardous Air Pollutants, New Source Performance Standards and New Source Review. We have incurred, and expect to continue to incur, substantial capital expenditures to maintain compliance with these and other air emission regulations that have been promulgated or may be promulgated or revised in the future.

In March 2004, Coffeyville Resources Refining & Marketing, LLC (CRRM) and Coffeyville Resources Terminal, LLC (CRT) entered into a Consent Decree (the 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 ownership and operation of our refinery and Phillipsburg terminal facilities. Under the Consent Decree, CRRM agreed to install controls to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) from its FCCU by January 1, 2011. In addition, pursuant to the Consent Decree, CRRM and CRT assumed certain cleanup obligations at the Coffeyville refinery and the Phillipsburg terminal facilities. The cost of complying with the Consent Decree is expected to be approximately $54 million, of which approximately $44 million is expected to be capital expenditures which does not include the cleanup obligations for historic contamination at the site that are being addressed pursuant to administrative orders issued under the Resource Conservation and Recovery Act (RCRA), and described in Impacts of Past Manufacturing. 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. To date, CRRM and CRT have materially complied with the Consent Decree. On June 30, 2009, CRRM submitted a force majeure notice to the EPA and KDHE in which CRRM indicated that it may be unable to meet the Consent Decree s January 1, 2011 deadline related to the installation of controls on

the FCCU because of delays caused by the June/July 2007 flood described below in 2007 Flood and Crude Oil Discharge. In February 2010, CRRM and the EPA reached an agreement in principle to a 15-month extension of the January 1, 2011 deadline to install controls that is awaiting final approval by the government before filing as a material modification to the existing Consent Decree. Pursuant to this agreement, CRRM will offset any incremental emissions resulting

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from the delay by providing additional controls to existing emission sources over a set timeframe. Final approval of the agreement is subject to additional review by other government agencies.

Over the course of the last decade, the EPA has embarked on a national Petroleum Refining Initiative alleging industry-wide noncompliance with four marquee issues under the Clean Air Act: New Source Review, Flaring, Leak Detection and Repair, and Benzene Waste Operations NESHAP. The Petroleum Refining Initiative has resulted in most refiners entering into consent decrees imposing civil penalties and requiring substantial expenditures for pollution control and enhanced operating procedures. The EPA has indicated that it will seek to have all refiners enter into global settlements pertaining to all marquee issues. Our current Consent Decree covers some, but not all, of the marquee issues. We have had preliminary discussions with EPA Region 7 under the Petroleum Refining Initiative. To date, the EPA has not made any specific claims or findings against us and we have not determined whether we will ultimately enter into a global settlement agreement with the EPA. We believe that if we were to enter into a global settlement we would be required to pay a civil penalty, but our incremental capital exposure would be limited primarily to the retrofit and replacement of heaters and boilers over a five to seven year timeframe.

Release Reporting

The release of hazardous substances or extremely hazardous substances into the environment is subject to release reporting of reportable quantities under federal and state environmental laws. Our facilities periodically experience releases of hazardous substances and extremely hazardous substances that could cause us to become the subject of a government enforcement action or third-party claims.

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 that were required to be met by 2006. 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.

In February 2004, the EPA granted us approval under a hardship waiver that deferred meeting final Ultra Low Sulfur Gasoline (ULSG) standards until January 1, 2011 in exchange for our meeting Ultra Low Sulfur Diesel (ULSD) requirements by January 1, 2007. We completed the construction and startup phase of our ULSD Hydrodesulfurization unit in late 2006 and met the conditions of the hardship waiver. We are currently continuing our project 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 $21.2 million during 2009, approximately $37.7 million during 2008, and $103.1 million during 2007 and we estimate that compliance will require us to spend approximately $22.0 million in 2010.

As a result of the 2007 flood, our refinery exceeded the annual average sulfur standard mandated by our hardship waiver. The EPA agreed to modify certain provisions of our hardship waiver, which gave CRRM short-term flexibility on sulfur content, and we agreed to meet the final ULSG annual average standard in 2010. We met the required sulfur standards under our hardship waiver for 2009, and expect to be able to comply with the remaining requirements of our hardship waiver.

Mobile Source Air Toxic II Emissions

In 2007, the EPA promulgated the Mobile Source Air Toxic II (MSAT II) rule that requires the reduction of benzene in gasoline by 2011. CRRM is considered a small refiner under the MSAT II rule and compliance with the rule is

extended until 2015 for small refiners. Because of the extended compliance date, CRRM has not begun engineering work at this time. We anticipate that capital expenditures to comply with the rule will not begin before 2013.

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Renewable Fuel Standards

In February 2010, the EPA finalized changes to the Renewable Fuel Standards (RFS2) which require the total volume of renewable transportation fuels sold or introduced in the U.S. to reach 12.95 billion gallons in 2010 and rise to 36 billion gallons by 2020. Due to mandates in the RFS2 requiring increasing volumes of renewable fuels to replace petroleum products in the U.S. motor fuel market, there may be a decrease in demand for petroleum products. In addition, CRRM may be impacted by increased capital expenses and production costs to accommodate mandated renewable fuel volumes. CRRM s small refiner status under the original Renewable Fuel Standards will continue under the RFS2 and therefore, CRRM is exempted from the requirements of the RFS2 through December 31, 2010.

Greenhouse Gas Emissions

It is probable that Congress will adopt some form of federal climate change legislation that may include mandatory greenhouse gas emission reductions, although the specific requirements and timing of any such legislation are uncertain at this time. In June 2009, the U.S. House of Representatives passed a bill that would create a nationwide cap-and-trade program designed to regulate emissions of carbon dioxide (CO_2), methane and other greenhouse gases. The bill would institute a cap on greenhouse gas emissions and establish a program to trade emission allowances. To comply with these cap regulations, companies could reduce actual emissions by installing equipment designed for the purpose of reducing greenhouse gases or by curtailing operations. Alternatively, compliance could be met by purchasing emissions allowances on the open market. A similar bill has been introduced in the U.S. Senate; however, Senate passage of the counterpart legislation is uncertain. It is also possible that the Senate may debate and pass alternative climate change bills that do not mandate a nationwide cap-and-trade program and instead focus on promoting renewable energy and energy efficiency.

In the absence of congressional legislation regulating greenhouse gas emissions, the EPA is moving ahead administratively under its federal Clean Air Act authority. On December 7, 2009, the EPA finalized its endangerment finding that greenhouse gas emissions, including CO_2, pose a threat to human health and welfare. The finding allows the EPA to regulate greenhouse gas emissions as air pollutants under the federal Clean Air Act. Additionally, the EPA has finalized rules on greenhouse gas emissions inventory reporting rules and has proposed a number of rules aimed at regulating greenhouse gas emissions. Because current major source thresholds under the Prevention of Significant Deterioration (PSD) and Title V programs of the federal Clean Air Act would subject small sources of greenhouse gas emissions to permitting requirements as major stationary sources, the EPA has proposed a Greenhouse Gas Tailoring Rule, which would raise the statutory major source threshold for greenhouse gas emissions in order to prevent such small sources from being considered major stationary sources subject to permitting requirements under the PSD and Title V rules. The EPA has further indicated that no stationary source will be required to obtain a federal Clean Air Act permit to cover greenhouse gas emissions in 2010 and that phase-in permit requirements will begin for the largest stationary sources in 2011. The EPA s endangerment finding, that Greenhouse Gas Tailoring Rule and certain other greenhouse gas emission rules proposed by the EPA have been challenged and will likely be subject to extensive litigation. For example, petitions have been filed on behalf of various parties in the United States Court of Appeals from the D.C. Circuit challenging EPA s endangerment finding. In addition, Senate bills to overturn the endangerment finding and bar the EPA from regulating greenhouse gas emissions, or at least to defer such action by the EPA under the federal Clean Air Act are under consideration.

In the absence of existing federal legislation or 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 Reduction 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.

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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 cash flows.

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 issued letters of credit of approximately $0.2 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 groundwater 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 2013 were estimated, as of December 31, 2009, to be as follows (in millions):

Facility	Site Investigation Costs	Capital Costs	Total O&M Costs Through 2013	Total Estimated Costs Through 2013
Coffeyville Refinery	$ 0.2	$	$ 0.9	$ 1.1
Phillipsburg Terminal	0.6		1.2	1.8
Total Estimated Costs	$ 0.8	$	$ 2.1	$ 2.9

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 2010, we will spend $3.7 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. We spent approximately $1.3 million in 2009 associated with related remediation.

Financial Assurance. We were required in the Consent Decree to establish financial assurance to cover the projected clean-up 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 in the amount of $9.0 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

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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, under certain circumstances, 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. As is the case with all companies engaged in similar industries, depending on the underlying facts and circumstances 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, disposed of or released. 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. 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.

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.

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. Our refinery was inspected in connection with OSHA s NEP program. The inspection commenced in September 2008 and was completed in March 2009, resulting in an assessed penalty of $32,500.

Employees

At December 31, 2009, 474 employees were employed in our petroleum business, 118 were employed by the nitrogen fertilizer business and 75 employees were employed by the Company and CRLLC at our offices in Sugar Land, Texas and Kansas City, Kansas.

At December 31, 2009, approximately 39% of our employees (all of whom work in our petroleum business) were covered by a collective bargaining agreement. These employees are affiliated with six unions of the Metal Trades Department of the AFL-CIO (Metal Trade Unions) and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO-CLC (United Steelworkers). A new collective bargaining agreement was entered into with the Metal Trade Unions effective August 31, 2008. No substantial changes were made to the prior agreement. This agreement expires in March 2013. In addition, a new collective bargaining agreement was entered into with the United Steelworkers on March 3, 2009. There were no substantial changes to the prior agreement. This agreement expires in March 2012. We believe that our relationship with our employees is good.

Available Information

Our website address is www.cvrenergy.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports, are available free of charge through our website

under Investors Relations, as soon as reasonably practicable after the electronic filing of these reports is made with the Securities and Exchange Commission (SEC). In addition, our Corporate Governance Guidelines, Codes of Ethics and Charters of the Audit Committee, the Nominating and Corporate Governance Committee and the Compensation Committee of the Board of Directors are available on our

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website. These guidelines, policies and charters are available in print without charge to any stockholder requesting them.

Trademarks, Trade Names and Service Marks

This Annual Report on Form 10-K for the year ended December 31, 2009 (the Report) may include our trademarks, including CVR Energy, the CVR Energy logo, Coffeyville Resources, the Coffeyville Resources logo, and the CVR Partners LP logo, each of which is either registered or for which we have applied for federal registration. This Report may also contain trademarks, service marks, copyrights and trade names of other companies.

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

The price volatility of crude oil, other feedstocks and refined products may have a material adverse effect on our earnings, profitability and cash flows.

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. When the margin between refined product prices and crude oil and other feedstock prices contracts, our earnings, profitability and cash flows are negatively affected. Refining margins historically have been volatile and are likely to continue to be volatile, as a result of a variety of factors including fluctuations in prices of crude oil, other feedstocks and refined products. Continued future volatility in refining industry margins may cause 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.

Our profitability is also impacted by the ability to purchase crude oil at a discount to benchmark crude oils, such as WTI, as we do not produce any crude oil and must purchase all of the crude oil we refine. These crude oils include, but are not limited to, crude oil from our gathering system. Crude oil differentials can fluctuate significantly based upon overall economic and crude oil market conditions. Declines in crude oil differentials can adversely impact refining margins, earnings and cash flows.

Refining margins are also impacted by domestic and global refining capacity. Continued downturns in the economy impact the demand for refined fuels and, in turn, generate excess capacity. In addition, the expansion and construction of refineries domestically and globally can increase refined fuel production capacity. Excess capacity can adversely impact refining margins, earnings and cash flows.

Volatile prices for natural gas and electricity affect our manufacturing and operating costs. Natural gas and electricity prices have been, and will continue to be, affected by supply and demand for fuel and utility services in both local and

regional markets.

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

If we cannot generate adequate cash flow or otherwise secure sufficient liquidity to meet our working capital needs or support our short-term and long-term capital requirements, we may be unable to meet our debt obligations, pursue our business strategies or comply with certain environmental standards, which would have a material adverse effect on our business and results of operations. As of December 31, 2009, we had cash and cash equivalents of $36.9 million and $86.2 million available under our revolving credit facility. Crude oil price volatility can significantly impact working capital on a week-to-week and month-to-month basis.

We have short-term and long-term capital needs. Our short-term working capital needs are primarily crude oil purchase requirements, which fluctuate with the pricing and sourcing of crude oil. Our long-term capital needs include capital expenditures we are required to make to comply with Tier II gasoline standards and the Consent Decree. Compliance with Tier II gasoline standards will require us to spend approximately $22 million in 2010. The costs of complying with the Consent Decree are expected to be approximately $54 million, of which approximately $44 million is expected to be capital expenditures. We also have budgeted capital expenditures for turnarounds at each of our facilities, and from time to time we are required to spend significant amounts for repairs when one or more facilities experiences temporary shutdowns. We also have significant debt service obligations. Our liquidity position will affect our ability to satisfy any of these needs.

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

We currently obtain the majority of our crude oil supply through the Supply Agreement with Vitol, which became effective on December 31, 2008 for an initial term of two years. On July 7, 2009, the Company entered into an amendment that extended the initial term of the Supply Agreement from two to three years ending December 31, 2011. The Supply Agreement 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 oil is refined and the yielded products are sold. If we were required to obtain our crude oil supply without the benefit of an intermediation agreement, our exposure to crude oil pricing risks may increase, 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.

In addition to the crude oil we gather locally in Kansas, Oklahoma, Colorado, Missouri, and Nebraska, we purchase an additional 85,000 to 100,000 bpd of crude oil to be refined into liquid fuel. We obtain a portion of our non-gathered crude oil, approximately 14% in 2009, from foreign sources. The majority of these non-gathered foreign sourced crude oil barrels were derived from Canada. In addition to the Canadian crudes, we have access to crude oils from Latin America, South America, the Middle East, West Africa and the North Sea. The actual amount of foreign crude oil we purchase is dependent on market conditions and will vary from year to year. We are subject to the political, geographic, and economic risks attendant to doing business with suppliers located in those regions. Disruption of production in any of such regions for any reason could have a material impact on other regions and our business. In the event that one or more of our traditional suppliers becomes unavailable to us, we may be unable to obtain an adequate supply of crude oil, or we may only be able to obtain our crude oil supply at unfavorable prices. As a result, we may experience a reduction in our liquidity and our results of operations could be materially adversely affected.

Severe weather, including hurricanes along the U.S. Gulf Coast, have in the past and could in the future interrupt our supply of crude oil. 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

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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.

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. 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 (those exceeding more than a twelve month period) 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. These competitors may have a greater ability to bear the economic risks inherent in all aspects 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 incentives or regulations, technological advances, consumer demand, improved pricing or otherwise, the greater the negative impact on pricing and demand for our products and

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our profitability. There are presently significant governmental incentives and consumer pressures to increase the use of alternative fuels in the United States.

Changes in our credit profile may affect our relationship with our suppliers, which could have a material adverse effect on our liquidity and our ability to operate our refineries at full capacity.

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 for our purchases or require us to post security prior to payment. Given the large dollar amounts and volume of our crude oil and other feedstock purchases, a burdensome change in payment terms may have a material adverse effect on our liquidity and our ability to make payments to our suppliers. This, in turn, could cause us to be unable to operate our refineries at full capacity. A failure to operate our refineries at full capacity could adversely affect our profitability and cash flows.

Risks Related to Our Nitrogen Fertilizer Business

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

Because most nitrogen fertilizer manufacturers rely on natural gas as their primary feedstock, and the cost of natural gas is a large component (approximately 90% based on historical data) of the total production cost of nitrogen fertilizers for natural gas-based nitrogen fertilizer manufacturers, the price of nitrogen fertilizers has historically generally correlated with the price of natural gas. The nitrogen fertilizer business does not hedge against declining natural gas prices. In addition, since our facilities use less natural gas than our competitors, any decrease in natural gas prices will disproportionately impact our operation by making us less competitive. Any decline in natural gas prices could have a material adverse impact on the results of operations, financial condition and cash flows of the nitrogen fertilizer business.

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 compared to natural gas based nitrogen fertilizer plants, 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 fertilizers 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.

The nitrogen fertilizer business is cyclical and volatile. Historically, periods of high demand and pricing have been followed by periods of declining prices and declining capacity utilization. Such cycles expose us to potentially significant fluctuations in our financial condition, cash flows and results of operations, which could result in volatility in the price of our common stock.

A significant portion of nitrogen fertilizer product sales expose 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.

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

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end-user markets, competition, supply and demand imbalances, and weather conditions, which have a greater relevance because of the seasonal nature of fertilizer application.

Demand for fertilizer products is dependent, in part, on demand for crop nutrients by the global agricultural industry. Nitrogen-based fertilizers demand is 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. A decrease in nitrogen fertilizer prices would have a material adverse effect on our results of operations, financial condition and cash flows of the nitrogen fertilizer business.

The nitrogen fertilizer business faces intense competition from other nitrogen fertilizer producers.

The nitrogen fertilizer business is subject to price competition from both U.S. and foreign sources, including competitors in the Persian Gulf, the Asia-Pacific region, the Caribbean and Russia. 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.

Adverse weather conditions during peak fertilizer application periods may have a material adverse effect on the 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 is seasonal, which may result in our carrying significant amounts of inventory and seasonal variations in working capital, and the inability to predict future seasonal nitrogen fertilizer demand accurately may result in excess inventory or product shortages.

The nitrogen fertilizer business is seasonal. Farmers tend to apply nitrogen fertilizer during two short application periods, one in the spring and the other in the fall. As a result, the strongest demand for our products typically occurs during the spring planting season, with a second period of strong demand following the fall harvest. In contrast, we and other nitrogen fertilizer producers generally produce our products throughout the year. As a result, we and/or our customers generally build inventories during the low demand periods of the year in order to ensure timely product availability during the peak sales seasons. The seasonality of nitrogen fertilizer demand results in sales volumes and net sales in the nitrogen fertilizer business being highest during the North American spring season and our working capital requirements in the nitrogen fertilizer business typically being highest just prior to the start of the spring season.

If seasonal demand exceeds our projections, we will not have enough product and our customers may acquire products from our competitors, which would negatively impact our profitability. If seasonal demand is less than we expect, we will be left with excess inventory and higher working capital and liquidity requirements.

The degree of seasonality of our business can change significantly from year to year due to conditions in the agricultural industry and other factors.

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The nitrogen fertilizer business results of operations, financial condition and cash flows 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 cash flows. 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 (approximately 74% on average during the last five years) of the pet coke it needs from our adjacent 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 refinery.

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

The nitrogen fertilizer business results of operations are highly dependent upon and fluctuate based upon business and economic conditions and governmental policies affecting the agricultural industry where our customers operate. These factors are outside of our control and may significantly affect our profitability.

The nitrogen fertilizer business results of operations are highly dependent upon business and economic conditions and governmental policies affecting the agricultural industry, which we cannot control. The agricultural products business can be affected by a number of factors. The most important of these factors, for U.S. markets, are:

- weather patterns and field conditions (particularly during periods of traditionally high nitrogen fertilizer consumption);
- quantities of nitrogen fertilizers imported to and exported from North America;
- current and projected grain inventories and prices, which are heavily influenced by U.S. exports and world-wide grain markets; and
- U.S. governmental policies, including farm and biofuel policies, which may directly or indirectly influence the number of acres planted, the level of grain inventories, the mix of crops planted or crop prices.

International market conditions, which are also outside of our control, may also significantly influence our operating results. The international market for nitrogen fertilizers is influenced by such factors as the relative value of the U.S. dollar and its impact upon the cost of importing nitrogen fertilizers, foreign agricultural policies, the existence of, or changes in, import or foreign currency exchange barriers in certain foreign markets, changes in the hard currency demands of certain countries and other regulatory policies of foreign governments, as well as the laws and policies of the United States affecting foreign trade and investment.

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The nitrogen fertilizer business relies on third party suppliers, including Linde, which owns an air separation plant that provides oxygen, nitrogen and compressed dry air to its gasifiers and the City of Coffeyville, which supplies it with electricity. A deterioration in the financial condition of a third party supplier, a mechanical problem with the air separation plant, or the inability of a third party supplier to perform in accordance with their contractual obligations could have a material adverse effect on our results of operations, financial condition and the cash flows of the nitrogen fertilizer business.

The nitrogen fertilizer operations depend in large part on the performance of third party suppliers, including Linde for the supply of oxygen, nitrogen and compressed dry air and the City of Coffeyville for the supply of electricity. The nitrogen fertilizer business operations could be adversely affected if there were a deterioration in Linde s financial condition such that the operation of the air separation plant was disrupted. Additionally, this air separation plant in the past has experienced numerous momentary interruptions, thereby causing interruptions in the nitrogen fertilizer business gasifier operations. Should Linde, the City of Coffeyville or any of the nitrogen fertilizer business other third party suppliers fail to perform in accordance with existing contractual arrangements, the nitrogen fertilizer business operation could be forced to halt. Alternative sources of supply could be difficult to obtain. Any shut down of operations at the nitrogen fertilizer business, even for a limited period, could have a material adverse effect on the results of operations, financial condition and cash flows of the nitrogen fertilizer business. We are currently engaged in litigation with the City of Coffeyville to enforce the pricing contained in a long-term contract for the supply of electricity; the City acknowledges an obligation to provide electricity but contends that the contract was suspended, permitting it to charge a higher tariff price.

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 the results of operations, financial condition and cash flows of the nitrogen fertilizer business. 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 the results of operations, financial condition and the cash flows of the nitrogen fertilizer business.

In addition, the nitrogen fertilizer business may incur significant losses or costs relating to the operation of railcars used for the purpose of carrying various products, including ammonia. Due to the dangerous and potentially toxic nature of the cargo, in particular ammonia, a railcar accident may have catastrophic results, including fires, explosions and pollution. These circumstances could result in severe damage and/or injury to property, the environment and human health. Litigation arising from accidents involving ammonia may result in the nitrogen fertilizer business or us being named as a defendant in lawsuits asserting claims for large amounts of damages, which could have a material adverse effect on the results of operations, financial condition and the cash flows of the nitrogen fertilizer business.

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 increase the insurance and other costs of railcars, freight costs of the nitrogen fertilizer business could significantly increase.

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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 the results of operations, financial condition and cash flows of the nitrogen fertilizer business.

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 fertilizer business products. In addition, new regulations could be implemented affecting the equipment used to ship its products.

Any delay in the nitrogen fertilizer business 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 cash flows of the nitrogen fertilizer business.

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

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

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 the results of operations, financial condition and cash flows of the nitrogen fertilizer business.

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 the results of operations, financial condition and cash flows of the nitrogen fertilizer business.

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

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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 fertilizer products, which could have a material adverse effect on the results of operations, financial condition and cash flows.

Risks Related to Our Entire Business

Instability and volatility in the capital and credit markets could have a negative impact on our business, financial condition, results of operations and cash flows.

The capital and credit markets experienced extreme volatility and disruption over the past two years. Our business, financial condition and results of operations could be negatively impacted by the difficult conditions and extreme volatility in the capital, credit and commodities markets and in the global economy. These factors, combined with volatile oil prices, declining business and consumer confidence and increased unemployment, have precipitated an economic recession in the U.S. and globally. The difficult conditions in these markets and the overall economy affect us in a number of ways. For example:

Although we believe we have sufficient liquidity under our revolving credit facility to run our business, under extreme market conditions there can be no assurance that such funds would be available or sufficient, and in such a case, we may not be able to successfully obtain additional financing on favorable terms, or at all.

Market volatility has exerted downward pressure on our stock price, which may make it more difficult for us to raise additional capital and thereby limit our ability to grow.

Our credit facility contains various financial covenants that we must comply with every quarter. Although we successfully amended these covenants in December 2008 and again in October 2009, due to the current economic environment there can be no assurance that we would be able to successfully amend the agreement in the future if we were to fall out of covenant compliance. Further, any such amendment could be very expensive.

Market conditions could result in our significant customers experiencing financial difficulties. We are exposed to the credit risk of our customers, and their failure to meet their financial obligations when due because of bankruptcy, lack of liquidity, operational failure or other reasons could result in decreased sales and earnings for us.

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, may change the coverage provided or may substantially increase premiums in the future.

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

down the nitrogen fertilizer facility for approximately two weeks and required significant expenditures to repair damaged equipment.

If our facilities experience a major accident or fire or other event or an interruption in supply or operations, our business could be materially adversely affected if the damage or liability exceeds the amounts of business interruption, property, terrorism and other insurance that we benefit from or maintain against these

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risks and successfully collect. As required under our existing credit facility, we maintain property and business interruption insurance. Our policy is capped at $1.0 billion and is subject to various deductibles and sub-limits for particular types of coverage (e.g., $150 million for a property 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 could not be claimed because it was lost within 45 days after the start of the flood.

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

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

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, end-use and application of fertilizer and the margins for our refined products are extensive and have become progressively more stringent. Violations of these laws and regulations or permit conditions can result in substantial penalties, injunctive relief requirements compelling installation of additional controls, civil and criminal sanctions, permit revocations and/or facility shutdowns.

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

Our business is inherently subject to accidental spills, discharges or other releases of petroleum or hazardous substances into the environment and neighboring areas. Past or future spills related to any of our current or former operations, including our refinery, pipelines, product terminals, fertilizer plant or

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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. We could be held strictly, and under certain conditions jointly and severally, liable under CERCLA and similar state statutes 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, and 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 may 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.

In March 2004, CRRM and CRT entered into a Consent Decree to address certain allegations of Clean Air Act violations by Farmland at our refinery in order to address the alleged violations and eliminate liabilities going forward. The costs of complying with the Consent Decree are expected to be approximately $54 million, which does not include the cleanup obligations for historic contamination at the site that are being addressed pursuant to administrative orders issued under RCRA and described in Item 1 Business Environmental Matters RCRA Impacts of Past Manufacturing. To date, CRRM and CRT have materially complied with the Consent Decree and 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. As described in Environmental, Health and Safety (EHS) Matters and The Federal Clean Air Act, CRRM has agreed in principle with the EPA to extend the refinery s deadline under the Consent Decree to install certain air pollution controls on its FCCU due to delays caused by the June/July 2007 flood. CRRM may also enter into a global settlement under the National Petroleum Refining Initiative, which would require us to install additional controls and pay a civil penalty, in consideration for broad releases from liability for violations of certain marquee Clean Air Act programs for refineries. A number of factors could affect our ability to meet the requirements imposed by the Consent Decree and have a material adverse effect on our results of operations, financial condition and profitability.

Two of our facilities, including our Coffeyville refinery and the Phillipsburg terminal (which operated as a refinery until 1991), have environmental contamination. We have assumed Farmland s responsibilities under certain RCRA administrative orders related to contamination at or that originated from the refinery (which includes portions of the nitrogen fertilizer plant) and the Phillipsburg terminal. If significant unknown liabilities that have been undetected to date by our 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.

Additionally, environmental and other laws and regulations have a significant effect on fertilizer end-use and application. 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 cash flows of the nitrogen fertilizer business.

Greenhouse gas emissions and proposed climate change laws and regulations could adversely affect our performance.

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 regulation and state actions to develop statewide or regional programs, which would require reductions in greenhouse gas emissions. At the federal legislative level, Congress may adopt some form of federal mandatory greenhouse gas emission reductions legislation or regulation, although the specific requirements and timing of any such legislation are uncertain at this time. In June 2009, the

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U.S. House of Representatives passed a bill that would create a nationwide cap-and-trade program designed to regulate emissions of carbon dioxide (CO_2), methane and other greenhouse gases. The bill would institute a cap on greenhouse gas emissions and establish a program to trade emission allowances. To comply with these cap regulations, companies could reduce actual emissions by installing equipment designed for the purpose of reducing greenhouse gases or by curtailing operations. Alternatively, compliance could be met by purchasing emissions allowances on the open market. A similar bill has been introduced in the U.S. Senate; however, Senate passage of the counterpart legislation is uncertain. It is also possible that the Senate may debate and pass alternative climate change bills that do not mandate a nationwide cap-and-trade program and instead focus on promoting renewable energy and energy efficiency.

In the absence of congressional legislation regulating greenhouse gas emissions, the EPA is moving ahead administratively under its federal Clean Air Act authority. On December 7, 2009, the EPA finalized its endangerment finding that greenhouse gas emissions, including CO_2, pose a threat to human health and welfare. The finding allows the EPA to regulate greenhouse gas emissions as air pollutants under the federal Clean Air Act. Additionally, the EPA has finalized rules on greenhouse gas emissions inventory reporting rules and has proposed a number of rules aimed at regulating greenhouse gas emissions. Because current major source thresholds under the Prevention of Significant Deterioration (PSD) and Title V programs of the federal Clean Air Act would subject small sources of greenhouse gas emissions to permitting requirements as major stationary sources, the EPA has proposed a Greenhouse Gas Tailoring Rule, which would raise the statutory major source threshold for greenhouse gas emissions in order to prevent such small sources from being considered major stationary sources subject to permitting requirements under the PSD and Title V rules. The EPA has further indicated that no stationary source will be required to obtain a federal Clean Air Act permit to cover greenhouse gas emissions in 2010 and that phase-in permit requirements will begin for the largest stationary sources in 2011. The EPA s endangerment finding, the Greenhouse Gas Tailoring Rule and certain other greenhouse gas emission rules have been challenged and will likely be subject to extensive litigation and the expectations for challenges and litigation are the same for any proposed rules aimed at regulating greenhouse gas emissions that are finalized by the EPA. For example, petitions have been filed on behalf of various parties in the United States Court of Appeals from the D.C. Circuit challenging EPA s endangerment finding. In addition, Senate bills to overturn the endangerment finding and bar the EPA from regulating greenhouse gas emissions, or at least to defer such action by the EPA under the federal Clean Air Act are under consideration.

In the absence of existing federal legislation or 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 Reduction 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.

The implementation of regulations proposed by the EPA and/or the passage of federal or state climate change legislation (including any such legislation that mandates a cap-and-trade system will likely 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. Increased costs associated with compliance with any future legislation or regulation of greenhouse gas emissions, if it occurs, may have a material adverse effect on our results of operations, financial condition and cash flows.

In addition, EPA regulations and/or federal or state legislation regulating the emission of greenhouse gasses may result in increased costs not only for our business but also for the consumers of refined fuels. Increased consumer costs for refined fuels costs could impact the demand for refined fuels produced through the use of fossil fuels. Decreased demand for refined fuels may have a material adverse effect on our results of operations, financial

condition and cash flows. In addition to the impact of increased regulation of greenhouse gas emissions on producers and consumers of refined fuels, climate change legislation and regulations would

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likely increase costs for agricultural producers that utilize our fertilizer products, thereby potentially decreasing demand for our fertilizer products.

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

We are subject to the requirements of 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 cash flows of the nitrogen fertilizer business if we are subjected to significant fines or compliance costs.

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 five largest customers in the petroleum business represented 48.8% of our petroleum sales for the year ended December 31, 2009. Further in the aggregate, the top five ammonia customers of the nitrogen fertilizer business represented 43.9% of its ammonia sales for the year ended December 31, 2009 and the top five UAN customers of the nitrogen fertilizer business represented 44.2% of its UAN sales for the same period. 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 cash flows of the nitrogen fertilizer business.

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;

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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 the Partnership s 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 cash flows of the nitrogen fertilizer business. There can be no assurance that we will be able to consummate any acquisitions or expansions, successfully integrate acquired entities, or generate positive cash flow at any acquired company or expansion project.

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

We are a holding company. Our subsidiaries conduct all of our operations and own substantially all of our assets. Consequently, our cash flow and our ability to meet our obligations or to pay dividends or make other distributions in the future will depend upon the cash flow of our subsidiaries and the payment of funds by our subsidiaries to us in the form of dividends, tax sharing payments or otherwise. In addition, CRLLC, 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.

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, 2009, we had total term debt outstanding of $479.5 million, $63.8 million in letters of credit outstanding and borrowing availability of $86.2 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 needs, capital 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, as we may be less capable of responding to adverse economic and industry conditions;

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placing restrictive financial and operating covenants in the agreements governing our and our subsidiaries long-term indebtedness and bank loans, including, in the case of certain indebtedness of subsidiaries, certain covenants that restrict the ability of subsidiaries to pay dividends or make other distributions to us;

exposing us to potential events of default (if not cured or waived) under financial and operating covenants contained in our or our subsidiaries debt instruments that could have a material adverse effect on our business, financial condition and operating results;

increasing our vulnerability to a downturn in general economic conditions or in pricing of our products; and

limiting our ability to react to changing market conditions in our industry and in our customers industries.

In addition, borrowings under our existing credit facility bear interest at variable rates subject to a LIBOR and base rate floor. 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, 2009 was $44.2 million. A 1% increase or decrease in the applicable interest rates under our credit facility, using average debt outstanding at December 31, 2009, would correspondingly change our interest expense by approximately $4.8 million per year. Our interest costs are also affected by our credit ratings. If our credit ratings decline in the future, the interest rates we are charged on debt under our credit facility could increase incrementally by 0.25%, up to 1.0%, contingent upon our credit rating.

In addition, changes in our credit ratings may affect the way crude oil and feedstock 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 liability and our ability to make payments to our suppliers.

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.

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, 2009, approximately 39% of our employees, all of whom work in our petroleum business, were represented by labor unions under collective bargaining agreements. Our collective bargaining agreement with the United Steelworkers will expire in March 2012 and our collective bargaining agreement with the Metal Trades Unions

will expire in March 2013. 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.

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Our business may suffer if any of our key senior executives or other key employees discontinues employment with us. Furthermore, a shortage of skilled labor or disruptions in our labor force may make it difficult for us to maintain labor productivity.

Our future success depends to a large extent on the services of our key senior executives and key senior employees. Our business depends on our continuing ability to recruit, train and retain highly qualified employees in all areas of our operations, including accounting, business operations, finance and other key back-office and mid-office personnel. Furthermore, our operations require skilled and experienced employees with proficiency in multiple tasks. The competition for these employees is intense, and the loss of these executives or employees could harm our business. If any of these executives or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any key man life insurance for any executives.

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 cash flows. 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 could be materially adversely affected by the cost of complying with new regulations.

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 NYSE rules and may elect not to comply with certain corporate governance requirements of the NYSE, 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; and
- the requirement that we have a compensation committee that is composed entirely of independent directors.

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

Compliance with and changes in the tax laws could adversely affect our performance.

We are subject to extensive tax liabilities, including United States and state income taxes and transactional taxes such as excise, sales/use, payroll, and franchise and withholding. New tax laws and regulations are continuously being enacted or proposed that could result in increased expenditures for tax liabilities in the future.

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Risks Related to Our Common Stock

The Goldman Sachs Funds and the Kelso Funds 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.

As of the date of this Report, the Goldman Sachs Funds and the Kelso Funds control approximately 27.9% and 36.4% of our outstanding common stock, respectively (collectively, they control approximately 64.3% of our outstanding common stock). Due to their equity ownership, the Goldman Sachs Funds and the Kelso Funds are able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other stockholders, the outcome of any corporate transaction or other matter submitted to our stockholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. The Goldman Sachs Funds and the Kelso Funds also have sufficient voting power to amend our organizational documents.

Conflicts of interest may arise between our principal stockholders and us. Affiliates of some of our principal stockholders engage in transactions with our company. 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 s partnership agreement, the Goldman Sachs Funds and the Kelso Funds have no obligation to offer the Partnership business opportunities. The Goldman Sachs Funds and the Kelso Funds may pursue acquisition opportunities for themselves that would be otherwise beneficial to the nitrogen fertilizer business and, as a result, these acquisition opportunities would not be available to the Partnership. The partnership agreement provides that the owners of its managing general partner, which include the Goldman Sachs Funds and the Kelso Funds, are permitted to engage in separate businesses that directly compete with the nitrogen fertilizer business and are not required to share or communicate or offer any potential business opportunities to the Partnership even if the opportunity is one that the Partnership might reasonably have pursued. 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. 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

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value upon a sale of the managing general partner interest would benefit the owners of the managing general partner, which are the Goldman Sachs Funds, the Kelso Funds and our senior management, rather than our company and our stockholders. Such increase in value could be significant if the Partnership performs well.

Further, decisions made by the Goldman Sachs Funds and the Kelso Funds with respect to their shares of common stock could trigger cash payments to be made by us to certain members of our senior management under the Phantom Unit Plans. Phantom points granted under the Amended and Restated CRLLC Phantom Unit Appreciation Plan (Plan I), or the Phantom Unit Plan I, and phantom points that we granted under the Amended and Restated CRLLC Phantom Unit Appreciation Plan (Plan II), or the Phantom Unit Plan II and together with the Phantom Unit Plan I, the Phantom Unit Plans , represent a contractual right to receive a cash payment when payment is made in respect of certain profits interests in CALLC and CALLC II. If either the Goldman Sachs Funds or the Kelso Funds sell any of the shares of common stock of CVR Energy which they beneficially own through CALLC or CALLC II, as applicable, they may then cause CALLC or CALLC II, 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 limited liability company agreements of CALLC and CALLC II, we would therefore be obligated to make cash payments under the Phantom Unit Plans. This could negatively affect our cash reserves, which could have a material adverse effect our results of operations, financial condition and cash flows.

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 86,329,237 shares of common stock were outstanding as of March 10, 2010. 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. In addition, another 7,376,264 shares of common stock were sold into the public market as a result of a secondary public offering that was completed on November 12, 2009, by CALLC II. The resale of shares by CALLC II was made possible by the filing of a shelf registration on February 12, 2009 whereby CALLC and CALLC II made eligible 7,376,265 and 7,376,264 shares, respectively. CALLC and CALLC II currently own 31,433,360 and 24,057,096 shares, respectively. CALLC and CALLC II have additional registration rights with respect to the remainder of their shares.

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

There are risks associated with the limited partnership structure through which we hold our interest in the Nitrogen Fertilizer Business. Some of these risks include:

Because we neither serve as, nor control, the managing general partner of the Partnership, the managing general partner may operate the Partnership in a manner with which we disagree or which is not in our interest. CVR GP, LLC or Fertilizer GP, which is owned by our controlling stockholders and senior

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

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.

The Partnership has a preferential right to pursue most corporate opportunities (outside of the refining business) before we can pursue them. Also, we have agreed with the Partnership that we will not own or operate a fertilizer business other than the Partnership (with certain exceptions).

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

If the managing general partner of the Partnership elects to pursue a public or private offering of Partnership interests, we will be required to use our commercially reasonable efforts to amend our credit facility to remove the Partnership as a guarantor. Any such amendment could results 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.

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

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

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.

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

Fertilizer GP will have no right to receive distributions in respect of its IDRs (i) until the Partnership has distributed all aggregate adjusted operating surplus generated by the Partnership during the period from October 24, 2007 through December 31, 2009 and (ii) for so long as the Partnership or its subsidiaries are guarantors under our credit facility (the date both of the actions described in (i) and (ii) are completed is referred to as the IDR Effective Date). The Partnership and its subsidiaries are currently guarantors under our credit facility, but if Fertilizer GP seeks to consummate a public or private offering, we will be required to use our commercially reasonable efforts to release the Partnership and its subsidiaries from our credit facility.

As of the IDR Effective Date, distributions of amounts greater than the aggregate adjusted operating surplus generated will be allocated between us and Fertilizer GP (and the holders of any other interests in the Partnership), and thereafter, the allocation will grant Fertilizer GP a greater percentage of the Partnership s distributions as more cash becomes available for distribution. After the IDR Effective Date, 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. Fertilizer GP s discretion in determining the level of cash reserves may materially adversely affect the Partnership s ability to make distributions to us.

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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 joint 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 IDR Effective Date, 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.

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

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

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

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

Fertilizer GP is 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.

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

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

The Fertilizer GP can require us to purchase its managing general partner interest in the Partnership. We may not have requisite funds to do so.

As the Partnership did not consummate an initial private or public offering by October 24, 2009, the 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.

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.

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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.

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	Coffeyville Resources: 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
Cowley County, KS (Hooser Station)	80	Own	Crude oil storage
Holdrege, NE	7	Own	Crude oil storage
Stockton, KS	6	Own	Crude oil storage

We also lease property for our executive office which is located at 2277 Plaza Drive in Sugar Land, Texas. Additionally, other corporate office space is leased in Kansas City, Kansas.

As of December 31, 2009, we had storage capacity for 767,000 barrels of gasoline, 1,068,000 barrels of distillates, 1,004,000 barrels of intermediates and 3,904,000 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 2,710,000 barrels of storage at Cushing, Oklahoma. We expect that our current owned and leased facilities will be sufficient for our needs over the next twelve months.

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 also incorporate by reference into this Part I, Item 3, the information regarding two lawsuits in Note 14, Commitments and Contingencies to our Consolidated Financial Statements as set forth in Part II, Item 7. Included in this note is a description of the Samson

litigation and the TransCanada litigation. Although we cannot predict with certainty the ultimate resolution of lawsuits, investigations or claims asserted against us, we do not believe that any currently pending legal proceeding or proceedings to which we are a party will have a material adverse effect on our business, financial condition or results of operations.

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PART II

Item 4. ***Market For Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common stock is listed on the NYSE 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:

2009:	**High**	**Low**
First Quarter	$ 6.71	$ 3.13
Second Quarter	10.74	5.24
Third Quarter	12.67	6.21
Fourth Quarter	13.89	6.50

2008:	**High**	**Low**
First Quarter	$ 30.94	$ 20.71
Second Quarter	28.88	18.17
Third Quarter	19.75	8.47
Fourth Quarter	9.01	2.15

Holders of Record

As of March 10, 2010, there were 450 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 distributions we may receive from the Partnership, to finance operations, expand our business, and make principal payments on our debt. 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 CRLLC, a subsidiary of ours, our credit facility limits the ability of CRLLC 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.

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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, 2009, as compared to the cumulative return of the Russell 2000 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 Russell 2000 Index and the industry peer group, and assumes the reinvestment of dividends where applicable. The closing market price for our common stock on December 31, 2009 was $6.86. 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, 2009
among CVR Energy, Inc., Russell 2000 Index and a peer group

This performance graph shall not be deemed filed for purposes of Section 18 of the Exchange Act or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended (the Securities Act), or the Exchange Act.

	Oct 07	Dec 07	Mar 08	Jun 08	Sep 08	Dec 08	Mar 09	Jun 09	Sep 09	Dec 09
CVR Energy, Inc.	100.00	123.16	113.73	95.06	42.07	19.75	27.36	36.20	61.43	33.88
Russell 2000 Index	100.00	93.59	84.05	84.26	83.02	61.02	51.65	62.10	73.83	76.40
Peer Group	100.00	84.02	58.83	50.99	40.49	27.68	33.43	27.26	31.52	28.34

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Equity Compensation Plans

The table below contains information about securities authorized for issuance under our long-term incentive plan as of December 31, 2009. This plan was approved by our stockholders in October 2007.

Equity Compensation Plan Information

Plan Category	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
Equity compensation plans approved by security holders:			
CVR Energy, Inc. Long- Term Incentive Plan	32,350	$ 19.08	7,102,644
Equity compensation plans not approved by security holders:			
None			
Total	32,350	$ 19.08	7,102,644

Included in the CVR Energy, Inc. 2007 Long-Term Incentive Plan are shares of non-vested common stock, stock appreciation rights, dividend equivalent rights, share awards and performance awards. As of December 31, 2009, 383,377 shares of non-vested common stock had been issued under this plan, of which 3,100 shares have been forfeited and 177,060 remain unvested.

Item 5. ***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 Statements of Operations Data for the years ended December 31, 2009, 2008 and 2007 and the selected consolidated financial information presented below under the caption Balance Sheet Data as of December 31, 2009 and 2008 has been derived from our audited consolidated financial statements included elsewhere in this Report, which financial statements have been audited by KPMG LLP, our independent registered public accounting firm. The consolidated financial information presented below under the caption Statement of Operations Data for the year ended December 31, 2006, the 233-day period ended December 31, 2005, the 174-day period ended June 23, 2005 and the consolidated financial information presented below under the caption Balance Sheet Data at December 31, 2007, 2006 and 2005, are derived from our audited consolidated financial statements that are not included in this Report.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, CALLC acquired all of the subsidiaries of Coffeyville Group Holdings, LLC (Predecessor). We refer to this acquisition as the 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. Included in the selected financial data below is a period of time when our business was operated by the Predecessor for the 174-days ended June 23, 2005. Since the assets and liabilities of Successor and Predecessor were each presented on a new basis of accounting, the financial information for Successor and Predecessor are not comparable.

We calculate earnings per share in 2007 and 2006 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 CALLC 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 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 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

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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 Predecessor because we operated under a different capital structure than what we currently operate under and, therefore, the information is not meaningful.

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.

	Successor					Predecessor
	Year Ended December 31,				233 Days Ended December 31,	174 Days Ended June 23,
	2009	2008	2007	2006	2005	2005
	(dollars in millions, except share data)					
Statements of Operations Data:						
Net sales	$ 3,136.3	$ 5,016.1	$ 2,966.9	$ 3,037.6	$ 1,454.3	$ 980.7
Cost of product sold(1)	2,547.7	4,461.8	2,308.8	2,443.4	1,168.1	768.0
Direct operating expenses(1)	226.0	237.5	276.1	199.0	85.3	80.9
Selling, general and administrative expenses(1)	68.9	35.2	93.1	62.6	18.4	18.4
Net costs associated with flood(2)	0.6	7.9	41.5			
Depreciation and amortization	84.9	82.2	60.8	51.0	24.0	1.1
Goodwill impairment(3)		42.8				
Operating income	$ 208.2	$ 148.7	$ 186.6	$ 281.6	$ 158.5	$ 112.3
Other income (expense), net(4)	(0.1)	(5.9)	0.2	(20.8)	0.4	(8.4)
Interest expense	(44.2)	(40.3)	(61.1)	(43.9)	(25.0)	(7.8)
Gain (loss) on derivatives, net	(65.3)	125.3	(282.0)	94.5	(316.1)	(7.6)
Income (loss) before income taxes and noncontrolling interest	$ 98.6	$ 227.8	$ (156.3)	$ 311.4	$ (182.2)	$ 88.5
Income tax (expense) benefit	(29.2)	(63.9)	88.5	(119.8)	63.0	(36.1)
Noncontrolling interest			0.2			
Net income (loss)(5)	$ 69.4	$ 163.9	$ (67.6)	$ 191.6	$ (119.2)	$ 52.4

Basic earnings (loss) per share(6)	$	0.80	$	1.90	$	(0.78)	$	2.22		
Diluted earnings (loss) per share(6)	$	0.80	$	1.90	$	(0.78)	$	2.22		
Weighted-average common shares outstanding(6)										
Basic		86,248,205		86,145,543		86,141,291		86,141,291		
Diluted		86,342,433		86,224,209		86,141,291		86,158,791		
Historical dividends:										
Per preferred unit(7)									$	0.70
Per common unit(7)									$	0.70
Management common units subject to redemption							$	3.1		
Common units							$	246.9		
Balance Sheet Data:										
Cash and cash equivalents	$	36.9	$	8.9	$	30.5	$	41.9	$	64.7
Working capital		235.4		128.5		10.7		112.3		108.0
Total assets		1,614.5		1,610.5		1,868.4		1,449.5		1,221.5
Total debt, including current portion		491.3		495.9		500.8		775.0		499.4
Noncontrolling interest(8)		10.6		10.6		10.6		4.3		
Total CVR stockholders equity/members equity		653.8		579.5		432.7		76.4		115.8
Cash Flow Data:										
Net cash flow provided by (used in):										
Operating activities		85.3		83.2		145.9		186.6		82.5	12.7
Investing activities		(48.3)		(86.5)		(268.6)		(240.2)		(730.3)	(12.3)
Financing activities		(9.0)		(18.3)		111.3		30.8		712.5	(52.4)
Other Financial Data:										
Capital expenditures for property, plant and equipment		48.8		86.5		268.6		240.2		45.2	12.3
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(9)		94.1		11.2		(5.6)		115.4		23.6	52.4

(1) Amounts are shown exclusive of depreciation and amortization.

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(2) Represents the write-off of approximate net costs associated with the June/July 2007 flood and crude oil spill that are not probable of recovery.

(3) Upon applying the goodwill impairment testing criteria under existing accounting rules during the fourth quarter of 2008, we determined that the goodwill in the petroleum segment was impaired, which resulted in a goodwill impairment loss of $42.8 million. This represented a write-off of the entire balance of the petroleum segment s goodwill.

(4) During the years ended December 31, 2009, 2008, 2007 and 2006 and the 174-days ended June 23, 2005, we recognized a loss of $2.1 million, $10.0 million, $1.3 million, $23.4 million and $8.1 million, respectively, on early extinguishment of debt.

(5) 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 (in millions):

	Successor					Predecessor
	Year Ended December 31,				233 Days Ended December 31	174 Days Ended June 23,
	2009	2008	2007	2006	2005	2005
Loss on extinguishment of debt(a)	$ 2.1	$ 10.0	$ 1.3	$ 23.4	$	$ 8.1
Inventory fair market value adjustment(b)					16.6	
Letter of credit expense and interest rate swap not included in interest expense(c)	13.4	7.4	1.8		2.3	
Major scheduled turnaround expense(d)		3.3	76.4	6.6		
Loss on termination of swap(e)					25.0	
Unrealized (gain) loss from Cash Flow Swap	40.9	(253.2)	103.2	(126.8)	235.9	
Share-based compensation(f)	8.8	(42.5)	44.1	16.9	1.1	4.0
Goodwill impairment(g)		42.8				

(a) Represents the write-off of: (1) $2.1 million of deferred financing costs in connection with the reduction, effective June 1, 2009, and eventual termination of the funded letter of credit facility on October 15, 2009; (2) $10.0 million of deferred financing costs in connection with the second amendment to our credit facility on December 22, 2008; (3) $1.3 million of deferred financing costs in connection with the repayment and termination of three credit facilities on October 26, 2007; (4) $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006; and (5) $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005.

(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 the time of the Acquisition, June 24, 2005.

(c) Consists of fees which are expensed to selling, general and administrative expenses in connection with the funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap and other letters of

credit outstanding. CRLLC reduced the funded letter of credit facility from $150.0 million to $60.0 million, effective June 1, 2009. As a result of the termination of the Cash Flow Swap effective October 8, 2009, the CRLLC was able to terminate the remaining $60.0 million funded letter of credit facility effective October 15, 2009. Although not included as interest expense in our Consolidated Statements of Operations, these fees are treated as such in the calculation of consolidated adjusted EBITDA in the credit facility.

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

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

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(f) Represents the impact of share-based compensation awards.

(g) Upon applying the goodwill impairment testing criteria under existing accounting rules during the fourth quarter of 2008, we determined that the goodwill in the petroleum segment was impaired, which resulted in a goodwill impairment loss of $42.8 million. This represented a write-off of the entire balance of the petroleum segment s goodwill.

(6) Earnings per share and weighted-average shares outstanding are shown on a pro forma basis for 2007 and 2006.

(7) Historical dividends per unit for the 174-day period ended June 23, 2005 is calculated on the ownership structure of the Predecessor.

(8) Noncontrolling interest at December 31, 2006 reflects common stock in two of our subsidiaries owned by our Chief Executive Officer (which were exchanged for shares of our common stock with an equivalent value prior to the consummation of our initial public offering). The noncontrolling interest at December 31, 2009, 2008 and 2007 reflects CAIII s ownership of the managing general partner interest and the IDRs of the Partnership. In our 2008 and 2007 Annual Report on Form 10-K, our noncontrolling interest was previously referred to as minority interest. As a result of the adoption of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) ASC 810 *Consolidation*, the term minority interest has been updated accordingly for all periods presented.

(9) Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the derivative transaction that was executed in conjunction with the Acquisition. On June 16, 2005, CALLC entered into the Cash Flow Swap with J. Aron & Company (J. Aron), a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned by CALLC to CRLLC on June 24, 2005. The Cash Flow Swap took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not a percentage of crude oil prices) crack spreads fell below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rose above the fixed level, we agreed to pay the difference to J. Aron. On October 8, 2009, the Cash Flow Swap was terminated and all remaining obligations were settled in advance of the original expiration date of June 30, 2010.

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

necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized gain or loss from Cash Flow Swap net of its related tax effect.

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our performance but instead should be utilized as a supplemental measure of financial performance in evaluating our business. Our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other

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companies. We believe that net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is important to enable investors to better understand and evaluate our ongoing operating results and allow for greater transparency in the review of our overall business, financial, operational and economic performance.

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

	Successor					Predecessor
	Year Ended December 31,				233 Days Ended December 31,	174 Days Ended June 23,
	2009	2008	2007	2006	2005	2005
Net income (loss) adjusted for unrealized gain (loss) from Cash Flow Swap	$ 94.1	$ 11.2	$ (5.6)	$ 115.4	$ 23.6	$ 52.4
Plus:						
Unrealized gain (loss) from Cash Flow Swap, net of tax effect	(24.7)	152.7	(62.0)	76.2	(142.8)	
Net income (loss)	$ 69.4	$ 163.9	$ (67.6)	$ 191.6	$ (119.2)	$ 52.4

Item 6. ***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 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 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 the section captioned 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.

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Overview and Executive Summary

We are an independent petroleum 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 in the form of ammonia and UAN.

We operate under two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2009, 2008 and 2007, we generated combined net sales of $3.1 billion, $5.0 billion and $3.0 billion, respectively, and operating income of $208.2 million, $148.7 million and $186.6 million, respectively. Our petroleum business generated $2.9 billion, $4.8 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 82%, 21% and 78% of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

Petroleum business. Our petroleum business includes a 115,000 bpd complex full coking medium-sour crude oil refinery in Coffeyville, Kansas. In addition, supporting businesses include (1) a crude oil gathering system serving Kansas, Oklahoma, western Missouri, eastern Colorado and southwestern Nebraska, (2) 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, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of 1.2 million barrels and (4) storage and terminal facilities for refined fuels and asphalt in Phillipsburg, Kansas.

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 oil variety in the world capable of being transported by pipeline. 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.

Crude oil is supplied to our refinery through our gathering system and by a Plains pipeline from Cushing, Oklahoma. We maintain capacity on the Spearhead Pipeline (as discussed more fully in note 14 to the financial statements) from Canada and have access to foreign and deepwater domestic crude oil via the Seaway Pipeline system from the U.S. Gulf Coast to Cushing. We also maintain leased storage in Cushing to facilitate optimal crude oil purchasing and blending. Our refinery blend consists of a combination of crude oil grades, including onshore and offshore domestic grades, various Canadian medium and heavy sours and sweet synthetics and from time-to-time a variety of South American, North Sea, Middle East and West African imported grades. The access to a variety of crude oils coupled with the complexity of our refinery allows us to purchase crude oil at a discount to WTI. Our crude consumed cost discount to WTI for 2009 was $4.65 per barrel compared to $2.12 per barrel in 2008 and $5.04 per barrel in 2007.

Nitrogen fertilizer business. The nitrogen fertilizer business consists of our interest in the Partnership, which is 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) a dual train gasifier complex each with a capacity of 84 million standard cubic foot per day, capable of processing approximately 1,400 tons per day of pet coke to produce hydrogen. In 2009, the nitrogen fertilizer business produced 435,184 tons of ammonia, of which approximately 64% was upgraded into 677,739 tons of UAN. The nitrogen fertilizer business generated net sales of $208.4 million, $263.0 million and $165.9 million, and operating income of $48.9 million, $116.8 million and $46.6 million, for the years ended December 31, 2009, 2008 and 2007, respectively.

The nitrogen fertilizer plant in Coffeyville, Kansas includes two pet coke gasifiers that produce 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

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coking process. On average during the last five years, more than 74% 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 pet coke supply agreement with the petroleum business.

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. In times of high natural gas prices, the use of low cost pet coke can provide us with a significant competitive advantage. The nitrogen fertilizer business competition utilizes natural gas to produce ammonia. Historically, pet coke has generally been a less expensive feedstock than natural gas on a per-ton of fertilizer produced basis.

CVR s Shelf Registration Statement

On March 6, 2009, the SEC declared effective our registration statement on Form S-3, which enabled (1) the Company to offer and sell from time to time, in one or more public offerings or direct placements, up to $250.0 million of common stock, preferred stock, debt securities, warrants and subscription rights and (2) certain selling stockholders to offer and sell from time to time, in one or more offerings, up to 15,000,000 shares of our common stock. As afforded by the registration statement, a stockholder, CALLC II, sold into the public market 7,376,264 shares on November 12, 2009.

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 changes in the value of our 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 addition to current market conditions, there are long-term factors that may impact the demand for refined products. These factors include mandated renewable fuel standards, proposed climate change laws and regulations, and increased mileage standards for vehicles.

In order to assess our operating performance, we compare our net sales, less cost of product sold, or our 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, we refer to the benchmark as the NYMEX 2-1-1 crack spread, or simply, the

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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 oil 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 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. We measure the cost advantage of our crude oil slate by calculating the spread between the price of our delivered crude oil and the price of WTI. 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 West Canadian Select (WCS) 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 oil and heavy sour crude oil we purchase as a percent of our total crude oil volume and will correlate more closely with such published differentials the heavier and more sour the crude oil slate. The WTI less WCS differential was $7.82, $18.72 and $22.94 per barrel for the years ended December 31, 2009, 2008 and 2007, respectively. The WTI less WTS differential was $1.70, $3.44 and $5.16 per barrel for the years ended December 31, 2009, 2008 and 2007, respectively. The Company s consumed crude oil differential was $4.65, $2.12 and $5.04 per barrel for the years ended December 31, 2009, 2008 and 2007, respectively.

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 in our region include the logistics cost for U.S. Gulf Coast refineries to ship into our region. The result of this logistical advantage and the fact the actual product specifications used to determine the NYMEX are different from the actual production in our 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 Ultra Low Sulfur Diesel PADD II, Group 3 vs. NYMEX basis, or Ultra Low Sulfur Diesel basis. If both gasoline and Ultra Low Sulfur Diesel basis are greater than zero, this means that prices in our marketing area exceed those used in the 2-1-1 crack spread. Since 2003, the market indicator for the Ultra Low Sulfur Diesel basis has been positive in all periods presented, including a decrease to $0.03 per barrel for 2009 from $4.22 per barrel for 2008 and $7.95 per barrel in 2007. Gasoline basis for 2009 was $(1.25) per barrel, compared to $0.12 per barrel in 2008 and $3.56 per barrel in 2007. 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. The refinery generally undergoes a facility turnaround every four to five years. The length of the turnaround is contingent upon the scope of work to be completed.

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

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target level, we consider risk mitigation activities usually through the purchase or sale of futures contracts on the 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 volatile swings in natural gas prices. Instead, our adjacent refinery supplies most of the pet coke feedstock needed by the nitrogen fertilizer business pursuant to a long-term pet 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 global supply and demand for, nitrogen fertilizer products which, in turn, depends on 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. Nitrogen fertilizer prices are also affected by other factors, such as local market conditions and the operating levels of competing facilities. An expansion or upgrade of competitors facilities, 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.

In addition, 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 our competitors production of nitrogen fertilizers. North American natural gas prices increased significantly in the summer months of 2008 and moderated from these high levels in the last half of 2008. Over the past several years, natural gas prices have experienced high levels of price volatility. This pricing and volatility has a direct impact on our competitors cost of producing nitrogen fertilizer.

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.

Because the nitrogen fertilizer plant has certain logistical advantages relative to end users of ammonia and UAN and demand relative to our production has remained high, the nitrogen fertilizer business primarily targets end users in the U.S. farm belt where it incurs lower freight costs as compared to U.S. Gulf Coast competitors. The nitrogen fertilizer business does not incur any barge or pipeline freight charges when it sells in these markets, giving us a distribution cost advantage over U.S. Gulf Coast producers and importers. 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 2009, the nitrogen fertilizer business upgraded approximately 64% 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 also directly affects 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,

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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 14% of direct operating expenses over the 24 months ended December 31, 2009. The average annual operating costs over the 24 months ended December 31, 2009 have approximated $85 million, of which substantially all are fixed in nature.

The nitrogen fertilizer business largest raw material expense is pet coke, which it purchases from the petroleum business and third parties. In 2009, 2008 and 2007, the nitrogen fertilizer business spent $12.8 million, $14.1 million and $13.6 million, respectively, 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 the price floor for nitrogen fertilizer products is 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 plant generally undergoes a facility turnaround every two years. The turnaround typically lasts 13-15 days each turnaround year and costs approximately $3 million to $5 million per turnaround. The facility underwent a turnaround in the fourth quarter of 2008, and the next facility turnaround is currently scheduled for the fourth quarter of 2010.

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 pet coke supply agreement mentioned above, under which the petroleum business sells 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 pet coke supply agreement is based on the lesser of a pet coke price derived from the price received by the Partnership for UAN (subject to a UAN-based price ceiling and floor) and a pet coke price index for pet coke. For the periods prior to our entering into the pet coke supply agreement, our historical financial statements reflected the cost of product sold (exclusive of depreciation and amortization) in the nitrogen fertilizer business based on a pet coke price of $15 per ton. 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 pet coke supply agreement had been in place in 2007, the new pet coke supply agreement would have resulted in an increase in cost of product sold (exclusive of depreciation and amortization) for the nitrogen fertilizer business and an increase in revenue for the petroleum business of $2.5 million for the year ended December 31, 2007. There would have been no impact to the consolidated financial statements as intercompany transactions are eliminated upon consolidation.

For the periods ending December 31, 2009 and 2008, the nitrogen fertilizer segment was charged $12.1 million and $13.2 million, respectively, for management services. In addition, due to the services agreement between the parties,

historical nitrogen fertilizer segment operating income would have increased $8.9 million for the year ended December 31, 2007, 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 decreases for these periods.

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The total change to operating income for the nitrogen fertilizer segment as a result of both the 20-year pet 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 during 2007, would have been an increase of $6.4 million for the year ended December 31, 2007.

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 southeast 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 severely flooded, sustained damage and required repair. In addition to costs incurred for repairs to the Coffeyville facilities, we also incurred costs related to a discharge of crude oil from the facility that occurred on or about July 1, 2007.

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. Due to the downtime, we experienced a significant revenue loss attributable to the property damage during the period when the facilities were not in operation in 2007.

Our results for the years ended December 31, 2009, 2008 and 2007 include net pretax costs, net of anticipated insurance recoveries, of $0.6 million, $7.9 million and $41.5 million, respectively, associated with the flood and related crude oil discharge. The 2007 flood and crude oil discharge had a significant adverse impact on our financial results for the year ended December 31, 2007, with substantially less of an impact for the years ended December 31, 2009 and 2008. The net costs associated with the flood have declined significantly over the comparable periods as the majority of the repairs and maintenance associated with the damage caused by the flood were completed by the second quarter of 2008. In addition, the majority of the environmental remedial actions were substantially complete as of January 31, 2009.

Refinancing and Prior Indebtedness

In January 2010, we made a voluntary unscheduled principal payment of $20.0 million on our tranche D term loans. In addition, we made a second voluntary unscheduled principal payment of $5.0 million in February 2010. Our outstanding term loan balance as of March 8, 2010 was $453.3 million. In connection with these voluntary prepayments, we paid a 2.0% premium totaling $0.5 million to the lenders of our credit facility. These unscheduled principal payments occurred primarily as a result of a partial reduction of our contango crude oil inventory in January and February 2010.

On October 2, 2009, CRLLC entered into a third amendment to its credit facility. The amendment was entered into, among other things, to provide financial flexibility to us through modifications to our financial covenants for the remaining term of the credit facility. Additionally, the amendment affords CVR (which is not a party to the credit agreement) the opportunity to incur indebtedness by allowing subsidiaries of CVR, which are parties to the credit agreement, to distribute dividends to CVR in order to fund interest payments of up to $20.0 million annually, so long

as CVR agrees, for the benefit of the lenders to contribute at least 35% of the net proceeds of such indebtedness to CRLLC for the purpose of repaying the tranche D term loans under the credit agreement. In addition, CVR is required to agree for the benefit of the lenders not to use the proceeds of such indebtedness to repurchase its capital stock or pay any dividend or other distributions on its capital stock.

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In connection with the third amendment, CRLLC incurred lender fees of approximately $2.6 million. These fees were recorded as deferred financing costs in the fourth quarter of 2009. In addition, CRLLC incurred third party costs of approximately $1.4 million primarily consisting of administrative and legal costs. Of the third party costs incurred, we expensed approximately $0.9 million in 2009. The remaining $0.5 million was recorded as additional deferred financing costs.

During June 2009, CRLLC successfully reduced the funded letter of credit from $150.0 million to $60.0 million. This funded letter of credit was issued in support of our Cash Flow Swap. As a result of the third amendment, CRLLC terminated the Cash Flow Swap in advance of its original expiration. As a result of the reduction of the funded letter of credit and eventual termination of the remaining $60.0 million funded letter of credit facility on October 15, 2009, previously deferred financing costs totaling approximately $2.1 million were written off. This amount is reflected on the Statements of Operations as a loss on extinguishment of debt.

On December 22, 2008, CRLLC amended its outstanding credit facility for the purpose of modifying certain restrictive covenants and related financial definitions. In connection with this amendment, we paid approximately $8.5 million of lender and third party costs. We immediately expensed $4.7 million of these costs and the remainder will be amortized to interest expense over the respective term of the term debt, revolver and funded letters of credit, as applicable. Previously deferred financing costs of $5.3 million were also written off at that time. The total amount expensed in 2008 of $10.0 million, is reflected on the Statements of Operations as a loss on extinguishment of debt.

In October 2007, we paid down $280.0 million of term debt with initial public offering proceeds. This reduced the associated future interest expense. Additionally, we repaid the $25.0 million secured facility and $25.0 million unsecured facility in their entirety with a portion of the net proceeds from the initial public offering. Also, the $75.0 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, CRLLC entered into several deferral agreements with J. Aron with respect to the Cash Flow Swap. These deferral agreements originally deferred to August 31, 2008 the payment of approximately $123.7 million (plus accrued interest). In 2008, a portion of amounts owed to J. Aron were ultimately deferred until July 31, 2009. During 2008, we made payments of $61.3 million, excluding accrued interest paid, reducing the outstanding payable to approximately $62.4 million (plus accrued interest) as of December 31, 2008. In January and February 2009, we prepaid $46.4 million of the deferred obligation, reducing the total principal deferred obligation to $16.1 million. On March 2, 2009, the remaining principal balance of $16.1 million was paid in full including accrued interest of $0.5 million resulting in CRLLC being unconditionally and irrevocably released from any and all of its obligations under the deferred agreements. In addition, J. Aron released the Goldman Sachs Funds and the Kelso Fund from any and all of their obligations to guarantee the deferred payment obligations.

Goodwill Impairment Charges

As a result of our annual review of goodwill in 2008, we recorded non-cash charges of $42.8 million during the fourth quarter, to write-off the entire balance of petroleum segment s goodwill. The write-off was associated with lower cash flow forecasts as well as a significant decline in market capitalization in the fourth quarter of 2008 that resulted in large part from severe disruptions in the capital and commodities markets.

2008 and 2007 Turnarounds

For 2008, we completed a planned turnaround of the nitrogen fertilizer plant in the fourth quarter of 2008 at a total cost of approximately $3.3 million, of which the majority of these costs were expensed in the fourth quarter. In April 2007, we completed a refinery turnaround at a total cost of approximately $76.4 million. The majority of these costs were expensed in the first quarter of 2007. The turnaround of our refining plant significantly impacted our financial results for 2007, as compared to a much lesser impact in 2008 from the nitrogen fertilizer plant turnaround. No planned major turnaround activities occurred in 2009.

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Cash Flow Swap

Until October 8, 2009, CRLLC had been a party to the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and a related party of ours. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represented approximately 14% of crude oil capacity for the period of July 1, 2009 through June 30, 2010. On October 8, 2009, the Cash Flow Swap was terminated and all remaining obligations were settled in advance. We have determined that the Cash Flow Swap did not qualify as a hedge for hedge accounting treatment under FASB ASC 815, *Derivatives and Hedging*. As a result, the Consolidated Statement of Operations reflects all the realized and unrealized gains and losses from this swap which has created significant changes between periods.

For the years ended December 31, 2009, 2008 and 2007, we recorded net realized losses of $14.3 million, $110.4 million and $157.2 million with respect to the Cash Flow Swap, respectively. In addition, for the year ended December 31, 2009, 2008 and 2007, we recorded net unrealized gains (losses) of $(40.9) million, $253.2 million and $(103.2) million, respectively.

Share-Based Compensation

Through a wholly-owned subsidiary, we have the two Phantom Unit Plans, whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. We account for awards under our Phantom Unit Plans as liability based awards. In accordance with FASB ASC 718, *Compensation Stock Compensation,* the expense associated with these awards for 2009 is based on the current fair value of the awards which was derived from a probability-weighted expected return method. The probability-weighted expected return method involves a forward-looking analysis of possible future outcomes, the estimation of ranges of future and present value under each outcome, and the application of a probability factor to each outcome in conjunction with the application of the current value of our common stock price with a Black-Scholes option pricing formula, as remeasured at each reporting date until the awards are settled.

Also, in conjunction with the initial public offering in October 2007, the override units of CALLC were modified and split evenly into override units of CALLC and CALLC II. As a result of the modification, the awards were no longer accounted for as employee awards and became subject to an accounting standard issued by the FASB which provides guidance regarding the accounting treatment by an investor for stock-based compensation granted to employees of an equity method investee. In addition, these awards are subject to an accounting standard issued by the FASB which provides guidance regarding the accounting treatment for equity instruments that are issued to other than employees for acquiring or in conjunction with selling goods or services. In accordance with this accounting guidance, the expense associated with the awards is based on the current fair value of the awards which is derived under the same methodology as the Phantom Unit Plans, as remeasured at each reporting date until the awards vest. For the years ended December 31, 2009, 2008 and 2007, we increased (reduced) compensation expense by $7.9 million, $(43.3) million and $43.5 million, respectively, as a result of the phantom and override unit share-based compensation awards. We expect to incur incremental share-based compensation expense to the extent our common stock price increases in the future.

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 an entity owned by our controlling stockholders and senior management. At December 31, 2009, we owned 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, except with respect to the IDRs. 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

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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 ASC 810-10, *Consolidation Variable Interest Entities* (ASC 810-10).

Using criteria set forth by ASC 810-10, management has determined that we are the primary beneficiary of the Partnership, although 100% of the managing general partner interest is owned by an 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 are required to consolidate the Partnership as a VIE 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 periodically reassess 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. 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 oil compared to sweet crude oil 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

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sours to the mid-continent will continue to cause wide swings in discounts. As a result of our expansion project, we increased throughput volumes of heavy sour Canadian crude oil and reduce our dependence on more expensive light sweet crude oil.

We believe that our 2.7 million barrels of crude oil storage in Cushing, Oklahoma allows us to take advantage of the contango market when such conditions exist. Contango markets are generally characterized by prices for future delivery that are higher than the current or spot price of a commodity. This condition provides economic incentive to hold or carry a commodity in inventory.

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.

According to the United States Department of Agriculture (USDA), U.S. farmers planted 86.4 million acres of corn in 2009 and 86.0 million acres in 2008. The global economic downturn has impacted the nitrogen fertilizer market, largely through uncertainty about both production and demand for ethanol. In the February 2010 long-term projections, the USDA has forecasted that 88.0 million acres of corn will be planted in 2010. We continue to expect that this level of production will translate to sustained demand for nitrogen fertilizer this spring. That particularly applies to demand for the upgraded forms of nitrogen fertilizer such as urea and UAN, as fall 2009 applications of ammonia nitrogen were well below historical levels due to weather and market uncertainty.

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, the trend in net ammonia capacity has been essentially flat since the late 1990 s, as new construction has been offset by plant closures in countries with high-cost feedstocks. The global credit crisis and economic downturn are also negatively impacting capacity additions.

Earnings for the nitrogen fertilizer business depend largely on the prices of nitrogen fertilizer products, of which the floor price is directly influenced by natural gas prices. Over the past several years, natural gas prices have experienced high levels of price volatility.

The nitrogen fertilizer business experienced an unprecedented pricing cycle in 2008. Prices for Mid Cornbelt and Southern Plains nitrogen-based fertilizers rose steadily during 2008 reaching a peak in late summer, before eventually declining sharply through year-end.

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. This Results of Operations section compares the year ended December 31, 2009 with the year ended December 31, 2008 and the year ended December 31, 2008 with the year ended December 31, 2007.

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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.

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

Consolidated Financial Results	Year Ended December 31, 2009	2008	2007
		(in millions)	
Net sales	$ 3,136.3	$ 5,016.1	$ 2,966.9
Cost of product sold (exclusive of depreciation and amortization)	2,547.7	4,461.8	2,308.8
Direct operating expenses (exclusive of depreciation and amortization)	226.0	237.5	276.1
Selling, general and administrative expense (exclusive of depreciation and amortization)	68.9	35.2	93.1
Net costs associated with flood(1)	0.6	7.9	41.5
Depreciation and amortization(2)	84.9	82.2	60.8
Goodwill impairment(3)		42.8	
Operating income	$ 208.2	$ 148.7	$ 186.6
Net income (loss)(4)	69.4	163.9	(67.6)
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(5)	94.1	11.2	(5.6)

(1) Represents the costs associated with the June/July 2007 flood and crude oil spill net of probable recoveries from insurance.

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

Consolidated Financial Results	Year Ended December 31, 2009	2008	2007
		(in millions)	
Depreciation and amortization excluded from cost of product sold	$ 2.9	$ 2.5	$ 2.4

Depreciation and amortization excluded from direct operating expenses	80.0	78.0	57.4
Depreciation and amortization excluded from selling, general and administrative expense	2.0	1.7	1.0
Depreciation included in net costs associated with flood			7.6
Total depreciation and amortization	$ 84.9	$ 82.2	$ 68.4

(3) Upon applying the goodwill impairment testing criteria under existing accounting rules during the fourth quarter of 2008, we determined that the goodwill in the petroleum segment was impaired, which resulted

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in a goodwill impairment loss of $42.8 million. This represented a write-off of the entire balance of the petroleum segment goodwill.

(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:

Consolidated Financial Results	Year Ended December 31, 2009	2008	2007
		(in millions)	
Loss on extinguishment of debt(a)	$ 2.1	$ 10.0	$ 1.3
Letter of credit expense & interest rate swap not included in interest expense(b)	13.4	7.4	1.8
Major scheduled turnaround expense(c)		3.3	76.4
Unrealized (gain) loss from Cash Flow Swap	40.9	(253.2)	103.2
Share-based compensation expense(d)	8.8	(42.5)	44.1
Goodwill impairment(e)		42.8	

(a) For 2009, the $2.1 million loss on extinguishment of debt represents the write-off of deferred financing costs associated with the reduction of the funded letter of credit facility of $150.0 million to $60.0 million, effective June 1, 2009, issued in support of the Cash Flow Swap and as a result of the termination of the Cash Flow Swap on October 8, 2009, the Company was able to terminate the remaining $60.0 million funded letter of credit facility effective October 15, 2009. For 2008, represents the write-off of $10.0 million in connection with the second amendment to our existing credit facility, which amendment was completed on December 22, 2008. For 2007, 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 fees which are expensed to selling, general and administrative expense in connection with the funded letter of credit facility issued in support of the Cash Flow Swap and other letters of credit outstanding. Although not included as interest expense in our Consolidated Statements of Operations, these fees are treated as such in the calculation of consolidated adjusted EBITDA in the credit facility. As noted above, the Cash Flow Swap was terminated effective October 8, 2009 and the related funded letter of credit facility was terminated effective October 15, 2009.

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

(d) Represents the impact of share-based compensation awards.

(e) Upon applying the goodwill impairment testing criteria under existing accounting rules during the fourth quarter of 2008, we determined that the goodwill in the petroleum segment was impaired, which resulted in a goodwill impairment loss of $42.8 million. This represented a write-off of the entire balance of the petroleum segment s goodwill.

(5) Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap results from adjusting for the derivative transaction that was executed in conjunction with the Acquisition. On June 16, 2005, Coffeyville Acquisition 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 to

Coffeyville Resources on June 24, 2005. The Cash Flow Swap took the form of three NYMEX swap agreements whereby if absolute (i.e., in dollar terms, not a percentage of crude oil prices) crack spreads fell below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rose above the fixed level, we agreed to pay the difference to J. Aron. On October 8, 2009, the Cash Flow Swap was terminated and all remaining obligations were settled in advance of the original expiration date of June 30, 2010.

We determined that the Cash Flow Swap did not qualify as a hedge for hedge accounting treatment under current U.S. GAAP. As a result, our periodic Statements of Operations reflect in each period material amounts of unrealized gains and losses based on the increases or decreases in market value of the unsettled position under the swap agreements which are accounted for as an asset or liability on our balance sheet,

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as applicable. As absolute crack spreads increased, we were required to record an increase in this liability account with a corresponding expense entry to be made to our Statements of Operations. Conversely, as absolute crack spreads declined, we were required to record a decrease in the swap related liability and post a corresponding income entry to our Statements of Operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap as a key indicator of our business performance. In managing our business and assessing its growth and profitability from a strategic and financial planning perspective, management and our board of directors considers our GAAP net income results as well as Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap enhances an 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 gain or loss from Cash Flow Swap net of its related tax effect.

Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is not a recognized term under GAAP and should not be substituted for net income as a measure of our performance but instead should be utilized as a supplemental measure of financial performance in evaluating our business. Our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies. We believe that net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap is important to enable investors to better understand and evaluate our ongoing operating results and allow for greater transparency in the review of our overall business, financial, operational and economic performance.

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

Consolidated Financial Results	**Year Ended December 31, 2009**	**2008**	**2007**
		(in millions)	
Net Income (loss) adjusted for unrealized gain or loss from Cash Flow Swap	$ 94.1	$ 11.2	$ (5.6)
Plus:			
Unrealized gain or (loss) from Cash Flow Swap, net of taxes	(24.7)	152.7	(62.0)
Net income (loss)	$ 69.4	$ 163.9	$ (67.6)

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008 (Consolidated)

Net Sales. Consolidated net sales were $3,136.3 million for the year ended December 31, 2009 compared to $5,016.1 million for the year ended December 31, 2008. The decrease of $1,879.8 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily due to a decrease in petroleum net sales of $1,839.4 million that resulted from lower product prices ($1,866.8 million), partially offset by slightly higher sales volumes ($27.4 million). The decline in average finished product prices was primarily driven from a decline in underlying feedstock costs compared to 2008. Nitrogen fertilizer net sales decreased $54.6 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 as a result of lower average plant gate prices ($91.3 million) and partially offset by an increase in overall sales volumes ($36.7 million).

Cost of Product Sold Exclusive of Depreciation and Amortization. Consolidated cost of product sold exclusive of depreciation and amortization was $2,547.7 million for the year ended December 31, 2009 as compared to $4,461.8 million for the year ended December 31, 2008. The decrease of $1,914.1 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 primarily resulted from a significant decrease in crude oil prices. On a year-over-year basis, our consumed crude oil prices decreased

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approximately 42% from an average price of $98.52 per barrel in 2008 compared to an average price of consumed crude of $57.64 per barrel in 2009. Partially offsetting the decrease in raw material prices was a 2.3% increase in crude oil throughput in 2009 compared to 2008. In addition, the nitrogen fertilizer business experienced higher costs of product sold as a result of increased sales volume, freight expense and hydrogen costs.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $226.0 million for the year ended December 31, 2009 as compared to $237.5 million for the year ended December 31, 2008. This decrease of $11.5 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was due to a decrease in petroleum and nitrogen fertilizer direct operating expenses of $9.8 million and $1.7 million, respectively. This decrease was primarily the result of net decreases in downtime repairs and maintenance ($13.0 million), outside services and other direct operating expenses ($9.1 million), production chemicals ($3.7 million) and turnaround ($3.4 million). These decreases were partially offset by net increases in labor ($9.8 million), property taxes ($4.2 million), catalyst ($1.0 million), energy and utilities ($0.6 million) and insurance ($0.2 million), combined with a decrease in the price we received for sulfur produced as a by-product of our manufacturing process ($2.0 million).

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses (exclusive of depreciation and amortization) were $68.9 million for the year ended December 31, 2009 as compared to $35.2 million for the year ended December 31, 2008. This $33.7 million increase in selling, general and administrative expenses over the comparable period was primarily the result of increases in share-based compensation ($45.3 million), administrative payroll ($4.2 million) and bank charges ($1.1 million), which were partially offset by decreases in expenses associated with outside services ($6.1 million), loss on disposition of assets ($5.7 million), bad debt expense ($3.0 million) and other selling, general and administrative expenses ($2.1 million).

Net Costs Associated with Flood. Consolidated net costs associated with flood for the year ended December 31, 2009 approximated $0.6 million as compared to $7.9 million for the year ended December 31, 2008.

Depreciation and Amortization. Consolidated depreciation and amortization was $84.9 million for the year ended December 31, 2009 as compared to $82.2 million for the year ended December 31, 2008. The increase in consolidated depreciation and amortization for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of the Company s increased investment in the refining and nitrogen fertilizer assets.

Goodwill Impairment. In connection with our 2009 annual goodwill impairment testing, we determined that the goodwill associated with our Nitrogen Fertilizer business was not impaired, thus no impairment charged was recorded for 2009. In 2008, we wrote-off approximately $42.8 million of goodwill in connection with our annual impairment testing. This goodwill was entirely attributable to the petroleum business.

Operating Income. Consolidated operating income was $208.2 million for the year ended December 31, 2009, as compared to operating income of $148.7 million for the year ended December 31, 2008, an increase of $59.5 million or 40.0%. For the year ended December 31, 2009, as compared to the year ended December 31, 2008, petroleum operating income increased $138.3 million primarily as a result of a decrease in the cost of product sold as well as the fact that in 2008 the petroleum segment recognized a goodwill impairment charge of $42.8 million compared to none in 2009. Partially offsetting the increase in operating income from the petroleum business is a decrease of $67.9 million related to nitrogen fertilizer operations. This decrease is primarily the result of lower plant gate prices for 2009 compared to 2008. In addition to decreased margins related to nitrogen fertilizer, consolidated selling, general and administrative expenses increased by $33.7 million for the year ended December 31, 2009 compared to the year ended December 31, 2008 primarily the result of increased share-based compensation expense.

Interest Expense. Consolidated interest expense for the year ended December 31, 2009 was $44.2 million as compared to interest expense of $40.3 million for the year ended December 31, 2008. This

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9.7% increase for the year ended December 31, 2009 as compared to the year ended December 31, 2008 primarily resulted from an increase in our weighted-average interest rate on a year-over-year basis.

Gain (Loss) on Derivatives, Net. For the year ended December 31, 2009, we incurred $65.3 million in net losses on derivatives. This compares to a $125.3 million net gain on derivatives for the year ended December 31, 2008. The change in gain (loss) on derivatives for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily attributable to the realized and unrealized losses on our Cash Flow Swap. For the year ended December 31, 2009 we recognized a $40.9 million unrealized loss on the cash flow swap compared to a $253.2 million unrealized gain for the year ended December 31, 2008. Unrealized losses on our Cash Flow Swap for the year ended December 31, 2009 reflect an increase in the crack spread values relative to December 31, 2008 on the unrealized positions comprising the Cash Flow Swap. Realized losses on the Cash Flow Swap for the year ended December 31, 2009 and the year ended December 31, 2008 were $14.3 million and $110.4 million, respectively. The primary cause of the remaining difference is attributable to an increase in net realized losses on other agreements and interest rate swap of $1.0 million offset by an increase in net unrealized gains of $8.4 million associated with the other agreements and interest rate swap.

Provision for Income Taxes. Income tax expense for the year ended December 31, 2009 was $29.2 million or 29.7% of income before incomes taxes and noncontrolling interest, as compared to an income tax expense for the year ended December 31, 2008 of $63.9 million or 28.1% of income before income taxes and noncontrolling interest. This is in comparison to a combined federal and state expected statutory rate of 39.7% for 2009 and 2008. Our effective tax rate increased in the year ended December 31, 2009 as compared to the year ended December 31, 2008 due to the correlation between the amount of credits generated due to the production of ultra low sulfur diesel fuel and Kansas state incentives generated under the High Performance Incentive Program (HPIP), in relative comparison with the pre-tax income level in each year. We also recognized a federal income tax benefit of approximately $4.8 million in 2009, compared to $23.7 million in 2008, on a credit of approximately $7.4 million in 2009, compared to a credit of approximately $36.5 million in 2008 related to the production of ultra low sulfur diesel. In addition, state income tax credits, net of federal expense, approximating $3.2 million were earned and recorded in 2009 that related to Kansas HPIP credits, compared to $14.4 million earned and recorded in 2008.

Net Income (Loss). For the year ended December 31, 2009, net income decreased to $69.4 million as compared to a net increase of $163.9 million for the year ended December 31, 2008.

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007 (Consolidated)

Net Sales. Consolidated net sales were $5,016.1 million for the year ended December 31, 2008 compared to $2,966.9 million for the year ended December 31, 2007. The increase of $2,049.2 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily due to an increase in petroleum net sales of $1,968.1 million that resulted from higher sales volumes ($1,318.5 million), coupled with higher product prices ($649.6 million). The sales volume increase for the refinery primarily resulted from a significant increase in refined fuel production volumes over the comparable period due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the June/July 2007 flood. Nitrogen fertilizer net sales increased $97.1 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007 as increases in overall sales volumes ($26.0 million) were coupled with higher plant gate prices ($71.1 million).

Cost of Product Sold (Exclusive of Depreciation and Amortization). Consolidated cost of product sold (exclusive of depreciation and amortization) was $4,461.8 million for the year ended December 31, 2008 as compared to $2,308.8 million for the year ended December 31, 2007. The increase of $2,153.0 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007 primarily resulted from a significant increase

in refined fuel production volumes over the comparable period in 2007 due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the June/July 2007 flood. In addition to the increased production in 2008, the cost of product sold increased sharply as a result of record high crude oil prices.

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Direct Operating Expenses (Exclusive of Depreciation and Amortization). Consolidated direct operating expenses (exclusive of depreciation and amortization) were $237.5 million for the year ended December 31, 2008 as compared to $276.1 million for the year ended December 31, 2007. This decrease of $38.6 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was due to a decrease in petroleum direct operating expenses of $58.1 million primarily the result of decreases in expenses associated with repairs and maintenance related to the refinery turnaround, taxes, outside services and direct labor, partially offset by increases in expenses associated with energy and utilities, production chemicals, repairs and maintenance, insurance, rent and lease expense, environmental compliance and operating materials. The nitrogen fertilizer business recorded a $19.4 million increase in direct operating expenses over the comparable period primarily due to increases in expenses associated with taxes, turnaround, outside services, catalysts, direct labor, slag disposal, insurance and repairs and maintenance, partially offset by reductions in expenses associated with royalties and other expense, utilities, environmental and equipment rental. The nitrogen fertilizer facility was subject to a property tax abatement that expired beginning in 2008. We have estimated our accrued property tax liability based upon the assessment value received by the county.

Selling, General and Administrative Expenses (Exclusive of Depreciation and Amortization). Consolidated selling, general and administrative expenses (exclusive of depreciation and amortization) were $35.2 million for the year ended December 31, 2008 as compared to $93.1 million for the year ended December 31, 2007. This $57.9 million positive variance over the comparable period was primarily the result of decreases in share-based compensation ($75.1 million) and other selling general and administrative expenses ($6.8 million) which were partially offset by increases in expenses associated with outside services ($10.5 million), loss on disposition of assets ($5.1 million), bad debt ($3.7 million) and insurance ($1.1 million).

Net Costs Associated with Flood. Consolidated net costs associated with flood for the year ended December 31, 2008 approximated $7.9 million as compared to $41.5 million for the year ended December 31, 2007.

Depreciation and Amortization. Consolidated depreciation and amortization was $82.2 million for the year ended December 31, 2008 as compared to $60.8 million for the year ended December 31, 2007. The increase in consolidated depreciation and amortization for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of the completion of several large capital projects in late 2007 and early 2008 in our petroleum business.

Goodwill Impairment. In connection with our annual goodwill impairment testing, we determined that the goodwill associated with our petroleum business was fully impaired. As a result, we wrote-off approximately $42.8 million in 2008 compared to none in 2007.

Operating Income. Consolidated operating income was $148.7 million for the year ended December 31, 2008, as compared to operating income of $186.6 million for the year ended December 31, 2007. For the year ended December 31, 2008, as compared to the year ended December 31, 2007, petroleum operating income decreased $113.0 million primarily as a result of as increase in the cost of product sold in 2008. In addition, the petroleum business recorded a non-cash charge of $42.8 million for the impairment of goodwill. For the year ended December 31, 2008 as compared to the year ended December 31, 2007, nitrogen fertilizer operating income increased by $70.2 million as increased direct operating expenses were more than offset by higher plant gate prices and sales volumes.

Interest Expense. Consolidated interest expense for the year ended December 31, 2008 was $40.3 million as compared to interest expense of $61.1 million for the year ended December 31, 2007. This 34% decrease for the year ended December 31, 2008 as compared to the year ended December 31, 2007 primarily resulted from an overall decrease in the index rates (primarily LIBOR) and a decrease in average borrowings outstanding during the comparable periods due to debt repayment in October 2007 with the proceeds of our initial public offering.

Gain (Loss) on Derivatives, Net. For the year ended December 31, 2008, we incurred $125.3 million in net gains on derivatives. This compares to a $282.0 million net loss on derivatives for the year ended December 31, 2007. This significant change in gain (loss) on derivatives for the year ended December 31,

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2008 as compared to the year ended December 31, 2007 was primarily attributable to the realized and unrealized gains (losses) on our Cash Flow Swap. Unrealized gains on our Cash Flow Swap for the year ended December 31, 2008 were $253.2 million and reflect a decrease 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, 2007 reported mark-to-market losses of $103.2 million and reflect an increase in the crack spread values on the unrealized positions comprising the Cash Flow Swap. Realized losses on the Cash Flow Swap for the year ended December 31, 2008 and the year ended December 31, 2007 were $110.4 million and $157.2 million, respectively. The decrease in realized losses over the comparable periods was primarily the result of lower average crack spreads for the year ended December 31, 2008 as compared to the year ended December 31, 2007. 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. 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, 2008, the Cash Flow Swap had a remaining term of approximately one year and six months whereas as of December, 2007, the remaining term on the Cash Flow Swap was approximately two years and six months. As a result of the shorter remaining term as of December 31, 2008, a similar change in crack spread will have a lesser impact on the unrealized gains or losses.

Provision for Income Taxes. Income tax expense for the year ended December 31, 2008 was $63.9 million or 28.1% of income before income taxes and noncontrolling interest, as compared to an income tax benefit of $88.5 million, or 56.6% of loss before income taxes and noncontrolling interest, for the year ended December 31, 2007. This is in comparison to a combined federal and state expected statutory rate of 39.7% for 2008 and 39.9% for 2007. Our effective tax rate decreased in the year ended December 31, 2008 as compared to the year ended December 31, 2007 due to the correlation between the amount of credits generated due to the production of ultra low sulfur diesel fuel and Kansas state incentives generated under the HPIP, in relative comparison with the pre-tax loss level in 2007 and pre-tax income level in 2008. We also recognized a federal income tax benefit of approximately $23.7 million in 2008, compared to $17.3 million in 2007, on a credit of approximately $36.5 million in 2008, compared to a credit of approximately $26.6 million in 2007 related to the production of ultra low sulfur diesel. In addition, state income tax credits, net of federal expense, approximating $14.4 million were earned and recorded in 2008 that related to the expansion of the facilities in Kansas, compared to $19.8 million earned and recorded in 2007.

Noncontrolling Interest. Noncontrolling interest for the year ended December 31, 2008 was zero compared to a loss of $0.2 million for the year ended December 31, 2007. Noncontrolling 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 (Loss). For the year ended December 31, 2008, net income increased to $163.9 million as compared to a net loss of $67.6 million for the year ended December 31, 2007.

Petroleum Business Results of Operations

Refining margin is a measurement calculated as the difference between net sales and cost of product 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 product sold (exclusive of depreciation and amortization) that we are able to sell refined products. Each of the components used in this calculation (net sales and cost of product 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

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

	Year Ended December 31,		
	2009	2008	2007
	(in millions)		
Petroleum Business Financial Results			
Net sales	$ 2,934.9	$ 4,774.3	$ 2,806.2
Cost of product sold (exclusive of depreciation and amortization)	2,514.3	4,449.4	2,300.2
Direct operating expenses (exclusive of depreciation and amortization)(1)	141.6	151.4	209.5
Net costs associated with flood	0.6	6.4	36.7
Depreciation and amortization	64.4	62.7	43.0
Gross profit(1)	$ 214.0	$ 104.4	$ 216.8
Plus direct operating expenses (exclusive of depreciation and amortization)	141.6	151.4	209.5
Plus net costs associated with flood	0.6	6.4	36.7
Plus depreciation and amortization	64.4	62.7	43.0
Refining margin(2)	$ 420.6	$ 324.9	$ 506.0
Goodwill impairment(3)	$	$ 42.8	$
Operating income	$ 170.2	$ 31.9	$ 144.9

	Year Ended December 31,		
	2009	2008	2007
	(dollars per barrel)		
Key Operating Statistics			
Refining margin (per crude oil throughput barrel)(1)	$ 10.65	$ 8.39	$ 18.17
Gross profit(1)	5.42	2.69	7.79
Direct operating expenses (exclusive of depreciation and amortization)	3.58	3.91	7.52

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	Year Ended December 31,					
	2009		2008		2007	
		%		%		%
Refining Throughput and Production Data (bpd)						
Throughput:						
Sweet	82,598	68.7	77,315	65.7	54,509	66.4
Light/medium sour	15,602	13.0	16,795	14.3	14,580	17.8
Heavy sour	10,026	8.3	11,727	10.0	7,228	8.8
Total crude oil throughput	108,226	90.0	105,837	90.0	76,317	93.0
All other feedstocks and blendstocks	12,013	10.0	11,882	10.0	5,748	7.0
Total throughput	120,239	100.0	117,719	100.0	82,065	100.0
Production:						
Gasoline	62,309	51.6	56,852	48.0	37,017	44.9
Distillate	46,909	38.8	48,257	40.7	34,814	42.3
Other (excluding internally produced fuel)	11,549	9.6	13,422	11.3	10,551	12.8
Total refining production (excluding internally produced fuel)	120,767	100.0	118,531	100.0	82,382	100.0
Product price (dollars per gallon):						
Gasoline		$ 1.68		$ 2.50		$ 2.20
Distillate		$ 1.68		$ 3.00		$ 2.28
Market Indicators (dollars per barrel)						
West Texas Intermediate (WTI) NYMEX		$ 62.09		$ 99.75		$ 72.36
Crude Oil Differentials:						
WTI less WTS (light/medium sour)		1.70		3.44		5.16
WTI less WCS (heavy sour)		7.82		18.72		22.94
NYMEX Crack Spreads:						
Gasoline		9.05		4.76		14.61
Heating Oil		8.03		20.25		13.29
NYMEX 2-1-1 Crack Spread		8.54		12.50		13.95
PADD II Group 3 Basis:						
Gasoline		(1.25)		0.12		3.56
Ultra Low Sulfur Diesel		0.03		4.22		7.95
PADD II Group 3 Product Crack:						
Gasoline		7.81		4.88		18.18
Ultra Low Sulfur Diesel		8.06		24.47		21.24
PADD II Group 3 2-1-1		7.93		14.68		19.71

(1)

In order to derive the gross profit per crude oil throughput barrel, we utilize the total dollar figures for gross profit as derived above and divide by the applicable number of crude oil throughput barrels for the period. In order to derive the direct operating expenses per crude oil throughput barrel, we utilize the total direct operating expenses, which does not include depreciation or amortization expense, and divide by the applicable number of crude oil throughput barrels for the period.

(2) Refining margin is a measurement calculated as the difference between net sales and cost of product 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

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our cost of product sold that we are able to sell refined products. Each of the components used in this calculation (net sales and cost of product sold (exclusive of depreciation and amortization)) is taken directly from our Statements 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. In order to derive the refining margin per crude oil throughput barrel, we utilize the total dollar figures for refining margin as derived above and divide by the applicable number of crude oil throughput barrels for the period. We believe that refining margin and refining margin per crude oil throughput barrel is important to enable investors to better understand and evaluate our ongoing operating results and for greater transparency in the review of our overall business, financial, operational and economic financial performance.

(3) Upon applying the goodwill impairment testing criteria under existing accounting rules during the fourth quarter of 2008, we determined that the goodwill of the petroleum business was impaired, which resulted in a goodwill impairment loss of $42.8 million in the fourth quarter. This goodwill impairment is included in the petroleum business operating income but is excluded in the refining margin and the refining margin per crude oil throughput barrel.

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008 (Petroleum Business)

Net Sales. Petroleum net sales were $2,934.9 million for the year ended December 31, 2009 compared to $4,774.3 million for the year ended December 31, 2008. The decrease of $1,839.4 million from the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of significantly lower product prices ($1,866.8 million), which is partially offset by slightly higher sales volumes ($27.4 million). Overall sales volumes of refined fuels for the year ended December 31, 2009 increased 0.9%, as compared to the year ended December 31, 2008. Our average sales price per gallon for the year ended December 31, 2009 for gasoline of $1.68 and distillate of $1.68 decreased by 33% and 44%, respectively, as compared to the year ended December 31, 2008. The refinery operated at 94% of its capacity during 2009 despite a 14-day unplanned outage of its fluid catalytic cracking unit and a 26-day unplanned outage of its vacuum unit in the third quarter, which resulted in reduced crude oil runs.

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 $2,514.3 million for the year ended December 31, 2009 compared to $4,449.4 million for the year ended December 31, 2008. The decrease of $1,935.1 million from the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of lower crude oil prices offset by the impact of FIFO accounting. Our average cost per barrel of crude oil consumed for the year ended December 31, 2009 was $57.46, compared to $98.52 for the comparable period of 2008, a decrease of approximately 42%. 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 a favorable FIFO impact when crude oil prices increase and an unfavorable FIFO impact when crude oil prices decrease. For the year ended December 31, 2009, we had a favorable FIFO impact of $67.9 million compared to an unfavorable FIFO impact of $102.5 million for the comparable period of 2008.

Refining margin increased from $324.9 million for the year ended December 31, 2008 to $420.6 million for the year ended December 31, 2009. The increase of $95.7 million is due primarily to the 42% decrease in the cost of crude oil consumed over the comparable periods. The decrease in cost of crude oil consumed resulted from the decline in crude oil prices from the record high prices of 2008 and our improved crude consumed discount to WTI achieved in 2009 as a result of the contango in the U.S. crude oil market. Negatively impacting the refining margin is a 32% decrease ($3.96 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and unfavorable regional differences between gasoline and distillate prices in our primary market region (the Coffeyville supply area) and those

of the NYMEX. The average gasoline basis for the year ended December 31, 2009 decreased by $1.37 per barrel to ($1.25) per barrel compared to $0.12 per barrel in the comparable period of 2008. The average distillate basis for the year ended

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December 31, 2009 decreased by $4.19 per barrel to $0.03 per barrel compared to $4.22 per barrel in the comparable period in 2008.

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 $141.6 million for the year ended December 31, 2009 compared to direct operating expenses of $151.4 million for the year ended December 31, 2008. The decrease of $9.8 million for the year ended December 31, 2009 compared to the year ended December 31, 2008 was the result of net decreases in expenses associated with outside services and other direct operating expenses ($8.4 million), downtime repairs and maintenance ($6.5 million), production chemicals ($3.8 million) and energy and utilities ($3.8 million). The decreases are partially offset by increases in expenses associated with direct labor ($7.4 million), property taxes ($4.9 million) and insurance ($0.4 million). On a per barrel of crude oil throughput basis, direct operating expenses per barrel of crude oil throughput for the year ended December 31, 2009 decreased to $3.58 per barrel as compared to $3.91 per barrel for the year ended December 31, 2008 principally due to net dollar decrease in expenses from year to year as detailed above.

Net Costs Associated with Flood. Petroleum net costs associated with the June/July 2007 flood for the year ended December 31, 2009 approximated $0.6 million as compared to $6.4 million for the year ended December 31, 2008.

Depreciation and Amortization. Petroleum depreciation and amortization was $64.4 million for the year ended December 31, 2009 as compared to $62.7 million for the year ended December 31, 2008, an increase of $1.7 million over the comparable periods.

Goodwill Impairment. In connection with our annual goodwill impairment testing, we determined our goodwill associated with our petroleum business was impaired in 2008. As a result, we wrote-off approximately $42.8 million in 2008. This amount represents the entire balance of goodwill at our petroleum business.

Operating Income. Petroleum operating income was $170.2 million for the year ended December 31, 2009 as compared to operating income of $31.9 million for the year ended December 31, 2008. This increase of $138.3 million from the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of an increase in the refining margin ($95.7 million), a reduction in direct operating expenses (exclusive of depreciation and amortization) ($9.8 million), a reduction in net costs associated with the flood ($5.8 million) and a non-cash charge related to the impairment of goodwill recorded in 2008 ($42.8 million). Partially offsetting these positive impacts was an increase in depreciation and amortization ($1.7 million) and an increase in selling, general and administrative expenses ($14.1 million) primarily attributable to an increase in share-based compensation expense.

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007 (Petroleum Business)

Net Sales. Petroleum net sales were $4,774.3 million for the year ended December 31, 2008 compared to $2,806.2 million for the year ended December 31, 2007. The increase of $1,968.1 million from the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of significantly higher sales volumes ($1,318.5 million), coupled with higher product prices ($649.6 million). Overall sales volumes of refined fuels for the year ended December 31, 2008 increased 41% as compared to the year ended December 31, 2007. The increased sales volume primarily resulted from a significant increase in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the June/July 2007 flood. Our average sales price per gallon for the year ended December 31, 2008 for gasoline of $2.50 and distillate of $3.00 increased by 14% and 32%, respectively, as

compared to the year ended December 31, 2007.

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The refinery operated at nearly 92% of its capacity during 2008 despite a 19-day unplanned outage of its fluid catalytic cracking unit in the fourth quarter, resulting in reduced crude oil runs.

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 $4,449.4 million for the year ended December 31, 2008 compared to $2,300.2 million for the year ended December 31, 2007. The increase of $2,149.2 million from the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of a significant increase in crude oil throughput compared to 2007. The increase in crude oil throughput resulted primarily from the refinery turnaround which began in February 2007 and was completed in April 2007, and the refinery downtime resulting from the June/July 2007 flood. In addition to the refinery turnaround and the flood, higher crude oil prices, increased sales volumes and the impact of FIFO accounting also impacted cost of product sold. Our average cost per barrel of crude oil for the year ended December 31, 2008 was $98.52, compared to $70.06 for the comparable period of 2007, an increase of 41%. Sales volume of refined fuels increased 41% for the year ended December 31, 2008 as compared to the year ended December 31, 2007 principally due to the refinery turnaround and June/July 2007 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 a favorable FIFO impact when crude oil prices increase and an unfavorable FIFO impact when crude oil prices decrease. For the year ended December 31, 2008, we had an unfavorable FIFO impact of $102.5 million compared to a favorable FIFO impact of $69.9 million for the comparable period of 2007.

Refining margin decreased from $506.0 million for the year ended December 31, 2007 to $324.9 million for the year ended December 31, 2008. The decrease of $181.1 million is due to the 10% decrease ($1.45 per barrel) in the average NYMEX 2-1-1 crack spread over the comparable periods and additionally unfavorable 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, 2008 decreased by $3.44 per barrel to $0.12 per barrel compared to $3.56 per barrel in the comparable period of 2007. The average distillate basis for the year ended December 31, 2008 decreased by $3.73 per barrel to $4.22 per barrel compared to $7.95 per barrel in the comparable period of 2007. In addition, reductions in crude oil discounts for sour crude oils evidenced by the $1.72 per barrel, or 33%, decrease in the spread between the WTI price, which is a market indicator for the price of light sweet crude oil, and the WTS price, which is an indicator for the price of sour crude oil, negatively impacted refining margin for the year ended December 31, 2008 as compared to the year ended December 31, 2007.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses (exclusive of depreciation and amortization) were $151.4 million for the year ended December 31, 2008 compared to direct operating expenses of $209.5 million for the year ended December 31, 2007. The decrease of $58.1 million for the year ended December 31, 2008 compared to the year ended December 31, 2007 was the result of decreases in expenses associated with repairs and maintenance related to the refinery turnaround ($72.7 million), taxes ($9.4 million), outside services ($3.3 million) and direct labor ($1.3 million), partially offset by increases in expenses associated with energy and utilities ($12.6 million), production chemicals ($5.6 million), downtime repairs and maintenance ($3.5 million), insurance ($2.5 million), rent and lease expense ($1.1 million), environmental compliance ($0.9 million) and operating materials ($0.8 million). On a per barrel of crude oil throughput basis, direct operating expenses per barrel of crude oil throughput for the year ended December 31, 2008 decreased to $3.91 per barrel as compared to $7.52 per barrel for the year ended December 31, 2007 principally due to refinery turnaround expenses and the related downtime associated with the turnaround and the June/July 2007 flood and the corresponding impact on overall crude oil throughput and production volume.

Net Costs Associated with Flood. Petroleum net costs associated with the June/July 2007 flood for the year ended December 31, 2008 approximated $6.4 million as compared to $36.7 million for the year ended December 31, 2007.

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Depreciation and Amortization. Petroleum depreciation and amortization was $62.7 million for the year ended December 31, 2008 as compared to $43.0 million for the year ended December 31, 2007, an increase of $19.7 million over the comparable periods. The increase in petroleum depreciation and amortization for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of the completion of several large capital projects in April 2007 and a significant capital project completed in February 2008.

Goodwill Impairment. In connection with our annual goodwill impairment testing, we determined our goodwill associated with our petroleum business was fully impaired. As a result, we wrote-off approximately $42.8 million in 2008 compared to none in 2007.

Operating Income. Petroleum operating income was $31.9 million for the year ended December 31, 2008 as compared to operating income of $144.9 million for the year ended December 31, 2007. This decrease of $113.0 million from the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of a decrease in refining margin ($181.1 million), an increase in depreciation and amortization ($19.7 million) and a non-cash charge related to the impairment of goodwill recorded in 2008 ($42.8 million). Partially offsetting these negative impacts was a significant decrease in direct operating expenses exclusive of depreciation and amortization ($58.1 million), a decrease in selling, general and administrative expenses ($42.1 million), primarily attributable to a decrease in our stock price which resulted in a reduction of share-based compensation expense, and a decrease in net costs associated with the flood ($30.3 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	Year Ended December 31, 2009	2008	2007
		(in millions)	
Net sales	$ 208.4	$ 263.0	$ 165.9
Cost of product sold (exclusive of depreciation and amortization)	42.2	32.6	13.0
Direct operating expenses (exclusive of depreciation and amortization)	84.5	86.1	66.7
Net costs associated with flood			2.4
Depreciation and amortization	18.7	18.0	16.8
Operating income	48.9	116.8	46.6

Key Operating Statistics	Year Ended December 31, 2009	2008	2007
Production (thousand tons):			
Ammonia (gross produced)(1)	435.2	359.1	326.7
Ammonia (net available for sale)(1)	156.6	112.5	91.8
UAN	677.7	599.2	576.9
Pet coke consumed (thousand tons)	483.5	451.9	449.8
Pet coke (cost per ton)	$ 27	$ 31	$ 30
Sales (thousand tons)(2):			
Ammonia	159.9	99.4	92.1

UAN	686.0	594.2	555.4
Total sales	845.9	693.6	647.5

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Key Operating Statistics	Year Ended December 31, 2009	2008	2007
Product pricing (plant gate) (dollars per ton)(2):			
Ammonia	$ 314	$ 557	$ 376
UAN	$ 198	$ 303	$ 211
On-stream factor(3):			
Gasification	97.4%	87.8%	90.0%
Ammonia	96.5%	86.2%	87.7%
UAN	94.1%	83.4%	78.7%
Reconciliation to net sales (dollars in millions):			
Freight in revenue	$ 21.3	$ 18.9	$ 13.9
Hydrogen revenue	0.8	9.0	
Sales net plant gate	186.3	235.1	152.0
Total net sales	$ 208.4	$ 263.0	$ 165.9

Market Indicators	Year Ended December 31, 2009	2008	2007
Natural gas NYMEX (dollars per MMBtu)	$ 4.16	$ 8.91	$ 7.12
Ammonia Southern Plains (dollars per ton)	$ 306	$ 707	$ 409
UAN Mid Cornbelt (dollars per ton)	$ 218	$ 422	$ 288

(1) The gross tons produced for ammonia represent the total ammonia produced, including ammonia produced that was upgraded into UAN. The net tons available for sale represent the ammonia available for sale that was not upgraded into UAN.

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

(3) 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 and the flood at the fertilizer facility, (i) the on-stream factors in 2009 adjusted for the Linde air separation unit outage would have been 99.3% for gasifier, 98.4% for ammonia and 96.1% for UAN, (ii) the on-stream factors in 2008 adjusted for turnaround would have been 91.7% for gasifier, 90.2% for ammonia and 87.4% for UAN, and (iii) the on-stream factors in 2007 adjusted for flood would have been 94.6% for gasifier, 92.4% for ammonia and 83.9% for UAN.

Year Ended December 31, 2009 compared to the Year Ended December 31, 2008 (Nitrogen Fertilizer Business)

Net Sales. Nitrogen fertilizer net sales were $208.4 million for the year ended December 31, 2009 compared to $263.0 million for the year ended December 31, 2008. The decrease of $54.6 million from the year ended December 31, 2009 as compared to the year ended December 31, 2008 was the result of increases in overall sales volumes ($36.7 million), offset by lower plant gate prices ($91.3 million).

In regard to product sales volumes for the year ended December 31, 2009, our nitrogen operations experienced an increase of 61% in ammonia sales unit volumes and an increase of 15% in UAN sales unit volumes. On-stream factors (total number of hours operated divided by total hours in the reporting period) for 2009 compared to 2008 were higher for all units of our nitrogen fertilizer operations, with the exception of the UAN plant, primarily due to unscheduled downtime and the completion of the bi-annual scheduled turnaround for the nitrogen fertilizer plant completed in October 2008. 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.

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Plant gate prices are prices at the designated delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both at our plant gate (sold plant) and delivered to 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, 2009 for ammonia and UAN were less than plant gate prices for the comparable period of 2008 by 44% and 34%, respectively. We believe the dramatic decrease in nitrogen fertilizer prices was in part due to the decrease in natural gas prices and overall economic and market conditions.

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 and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the year ended December 31, 2009 was $42.2 million compared to $32.6 million for the year ended December 31, 2008. The increase of $9.6 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of inventory change of $6.1 million, $2.6 million increase in freight expense and increase in hydrogen costs of $1.6 million, partially offset by a decrease in pet coke cost of $1.2 million over the comparable periods.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses for our 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 fertilizer direct operating expenses (exclusive of depreciation and amortization) for the year ended December 31, 2009 were $84.5 million as compared to $86.1 million for the year ended December 31, 2008. The decrease of $1.6 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of net decreases in expenses associated with downtime repairs and maintenance ($6.5 million), turnaround ($3.4 million), outside services and other direct operating expenses ($0.7 million), property taxes ($0.7 million), and insurance ($0.2 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with utilities ($4.4 million), labor ($2.4 million), catalyst ($1.0 million) and combined with a decrease in the price we receive for sulfur produced as a by-product of our manufacturing process ($2.0 million).

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $18.7 million for the year ended December 31, 2009 as compared to $18.0 million for the year ended December 31, 2008.

Operating Income. Nitrogen fertilizer operating income was $48.9 million for the year ended December 31, 2009, or 23% of net sales, as compared to $116.8 million for the year ended December 31, 2008, or 44% of net sales. This decrease of $67.9 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was the result of a decline in the nitrogen fertilizer margin ($64.2 million), increases in selling, general and administrative expenses ($4.7 million), primarily attributable to an increase in share-based compensation expense and depreciation and amortization ($0.7 million) partially off set by lower direct operating costs ($1.6 million).

Year Ended December 31, 2008 compared to the Year Ended December 31, 2007 (Nitrogen Fertilizer Business)

Net Sales. Nitrogen fertilizer net sales were $263.0 million for the year ended December 31, 2008 compared to $165.9 million for the year ended December 31, 2007. The increase of $97.1 million from the year ended December 31, 2008 as compared to the year ended December 31, 2007 was the result of increases in overall sales volumes ($26.0 million) and higher plant gate prices ($71.1 million).

In regard to product sales volumes for the year ended December 31, 2008, our nitrogen operations experienced an increase of 8% in ammonia sales unit volumes and an increase of 7% in UAN sales unit volumes. On-stream factors (total number of hours operated divided by total hours in the reporting period) for 2008 compared to 2007 were

slightly lower for all units of our nitrogen fertilizer operations, with the exception of the UAN plant, primarily due to unscheduled downtime and the completion of the bi-annual scheduled turnaround for the nitrogen fertilizer plant completed in October 2008. It is typical to experience

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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. After the 2008 turnaround, the gasifier on-stream rate rose to nearly 100% for the remainder of the year.

Plant gate prices are prices at the designated delivery point less any freight cost we absorb to deliver the product. We believe plant gate price is meaningful because we sell products both at our plant gate (sold plant) and delivered to 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, 2008 for ammonia and UAN were greater than plant gate prices for the comparable period of 2007 by 48% and 43%, respectively. This dramatic increase in nitrogen fertilizer prices was not the direct result of an increase in natural gas prices, but rather the result of increased demand for nitrogen-based fertilizers due to historically low endings stocks of global grains and a surge in the prices of corn, wheat and soybeans, the primary crops in our region. This increase in demand for nitrogen-based fertilizers has created an environment in which nitrogen fertilizer prices have disconnected from their traditional correlation with natural gas prices.

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 and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the year ended December 31, 2008 was $32.6 million compared to $13.0 million for the year ended December 31, 2007. The increase of $19.6 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of a change in intercompany accounting for hydrogen reimbursement ($17.8 million) and a $5.1 million increase in freight expense, partially offset by a $3.7 million change in inventory over the comparable periods. For the year ended December 31, 2007, hydrogen reimbursement was included in the cost of product sold (exclusive of depreciation and amortization). For the year ended December 31, 2008, hydrogen reimbursement has been included in net sales. The amounts eliminate in consolidation.

Direct Operating Expenses (Exclusive of Depreciation and Amortization). Direct operating expenses for our 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 fertilizer direct operating expenses (exclusive of depreciation and amortization) for the year ended December 31, 2008 were $86.1 million as compared to $66.7 million for the year ended December 31, 2007. The increase of $19.4 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily the result of increases in expenses associated with taxes ($11.6 million), turnaround ($3.3 million), outside services ($2.8 million), catalysts ($1.7 million), direct labor ($0.8 million), insurance ($0.6 million), slag disposal ($0.5 million), and downtime repairs and maintenance ($0.5 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with royalties and other expense ($2.0 million), utilities ($0.5 million), environmental ($0.4 million) and equipment rental ($0.3 million).

Net Costs Associated with Flood. For the year ended December 31, 2008, the nitrogen fertilizer business did not record any net costs associated with flood. This compares to $2.4 million of net costs associated with flood for the year ended December 31, 2007.

Depreciation and Amortization. Nitrogen fertilizer depreciation and amortization increased to $18.0 million for the year ended December 31, 2008 as compared to $16.8 million for the year ended December 31, 2007.

Operating Income. Nitrogen fertilizer operating income was $116.8 million for the year ended December 31, 2008, or 44% of net sales, as compared to $46.6 million for the year ended December 31, 2007, or 28% of net sales. This increase of $70.2 million for the year ended December 31, 2008 as compared to the year ended December 31, 2007

was partially the result of an increase in both plant gate prices ($71.1 million) and an increase in overall sales volumes ($26.0 million). Partially offsetting the positive effects of plant gate prices and sales volumes was an increase in direct operating expenses excluding depreciation and amortization associated with taxes ($11.6 million), turnaround ($3.3 million), outside services ($2.8 million), catalysts ($1.7 million), direct labor ($0.8 million), insurance ($0.6 million), slag disposal ($0.5 million), and repairs and maintenance ($0.5 million). These increases in direct operating expenses were partially offset by

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reductions in expenses associated with royalties and other expense ($2.0 million), utilities ($0.5 million), environmental ($0.4 million), and equipment rental ($0.3 million).

Liquidity and Capital Resources

Our primary sources of liquidity currently consist of cash generated from our operating activities, existing cash and cash equivalent 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.

We believe that our cash flows from operations and existing cash and cash equivalent balances, together with borrowings under our existing revolving credit facility as necessary, 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, 2009, we had cash and cash equivalents of $36.9 million. As of December 31, 2009 and March 8, 2010, we had no amounts outstanding under our revolving credit facility and aggregate availability of $86.2 million and $114.2 million, respectively, under our revolving credit facility. At March 8, 2010, we had cash and cash equivalents of $44.3 million.

Working capital at December 31, 2009 was $235.4 million, consisting of $426.0 million in current assets and $190.6 million in current liabilities. Working capital at December 31, 2008 was $128.5 million, consisting of $373.4 million in current assets and $244.9 million in current liabilities.

Credit Facility

Our credit facility currently consists of tranche D term loans with an outstanding balance of $479.5 million at December 31, 2009 and a $150.0 million revolving credit facility. The tranche D term loans outstanding as of December 31, 2009 are subject to quarterly principal amortization payments of 0.25% of the outstanding balance, 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.

In January 2010, we made a voluntary unscheduled principal payment of $20.0 million on our tranche D term loans. In addition, we made a second voluntary unscheduled principal payment of $5.0 million in February 2010. Our outstanding term loan balance as of March 8, 2010 was $453.3 million. In connection with these voluntary prepayments, we paid a 2.0% premium totaling $0.5 million to the lenders of our credit facility. These unscheduled principal payments occurred primarily as a result of a partial reduction of our contango crude oil inventory in January and February 2010.

The revolving credit facility of $150.0 million provides for direct cash borrowings for general corporate purposes and on a short-term basis. Availability under the revolving credit facility is reduced by letters of credit issued under the revolving credit facility, which are subject to a $75.0 million sub-limit. As of December 31, 2009, we had $63.8 million of outstanding letters of credit consisting of: $0.2 million in letters of credit in support of certain environmental obligations, $30.6 million in letters of credit to secure transportation services for crude oil ($27.4 million of which relates to TransCanada Keystone Pipeline, LP (TransCanada) petroleum transportation service

agreements, the validity of which we are contesting), $5.0 million standby letter of credit issued in connection with the Interest Rate Swap and a $28.0 million standby letter of credit issued in support of the purchase of feedstocks. On January 11, 2010, the $28.0 million standby letter of credit was reduced to $0. The $5.0 million standby letter of credit was required by the counterparty to the Interest Rate Swap as the counterparty was previously collateralized by the funded letter of credit facility that was terminated on October 15, 2009. The revolving loan commitment expires on

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December 28, 2012. We have the 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, 2009, we had available $86.2 million under the revolving credit facility.

Since the inception of the Cash Flow Swap, and at all times prior to its termination, we maintained a $150.0 million funded letter of credit facility which provided credit support for our obligations under the Cash Flow Swap. Contingent upon the requirements of the Cash Flow Swap, we had the ability to reduce the funded letter of credit at any time upon written notice to the lenders. During 2009, we were able to reduce the funded letter of credit from $150.0 million to $60.0 million effective June 1, 2009. In connection with the termination of the Cash Flow Swap on October 8, 2009, we were able to terminate the remaining $60.0 million funded letter of credit on October 15, 2009.

The credit facility incorporates the following pricing by facility type:

Tranche D term loans and revolving credit loans each bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case the interest-rate margin (as discussed below) or, at the borrower s option, (b) LIBOR plus the interest-rate margin.

Revolving credit lenders each receive commitment fees equal to the amount of undrawn revolving credit loans, multiplied by 0.5% per annum.

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

As of December 31, 2009, the interest-rate margin applicable to the tranche D term loans and revolving credit loans was 5.25%. The interest-rate margin could increase incrementally by 0.25%, up to 1.0%, or decrease by 0.25%, based on changes in credit rating by either Standard & Poor s (S&P) or Moody s.

On December 22, 2008, CRLLC entered into a second amendment to its credit facility. The amendment was entered into, among other things, to amend the definition of consolidated adjusted EBITDA to add a FIFO adjustment which applied for the year ending December 31, 2008 through the quarter ending September 30, 2009. This FIFO adjustment was to be used for the purpose of testing compliance with the financial covenants under the credit facility until the quarter ending June 30, 2010. CRLLC sought and obtained the amendment due to the dramatic decrease in the price of crude oil during the months preceding the amendment and the effect that such crude oil price decrease would have had on the measurement of the financial ratios under the credit facility. As part of the amendment, CRLLC s interest-rate margin increased by 2.50%, and LIBOR and the base rate were set at a minimum of 3.25% and 4.25%, respectively.

On October 2, 2009, CRLLC entered into a third amendment to its credit facility. The third amendment (among other things):

Permitted CRLLC to terminate the Cash Flow Swap with J. Aron and to return to the lenders $60.0 million of funded letter of credit deposits in connection therewith. CRLLC terminated the funded letter of credit facility effective October 15, 2009.

Enables CRLLC and subsidiaries of CVR, which are parties to the credit agreement, to pay up to $20 million in dividends during any fiscal year to CVR (which is not a party to the credit agreement) to allow CVR to make interest payments on any indebtedness it may incur, subject to certain conditions.

Requires that 35% of net proceeds obtained through indebtedness issued by CVR Energy, Inc. be used to prepay the tranche D term loans.

Requires CRLLC to pay a premium on certain voluntary prepayments and mandatory prepayments of the term loans in an amount equal to (a) 2.00% for the 1-year period after the effective date of the third amendment and (b) 1.00% for the period beginning at the end of such 1-year period and ending on the second anniversary of the effective date of the third amendment.

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Reduces the percentage of consolidated excess cash flow that has to be used to prepay loans from 100% to 75%. As such, 75% of consolidated excess cash flow less 100% of voluntary prepayments made during the fiscal year must be used to prepay outstanding loans (excluding repayments of revolving or swing line loans).

Extends the application of the FIFO adjustment obtained in connection with the second amendment through the remaining term of the credit facility at a reduced level of 75%.

Provides greater flexibility with respect to the financial covenants by adjusting the leverage ratio and interest coverage ratio to 2.75:1.00 and 3.00:1.00, respectively, through the remaining term of the credit facility.

Increases the interest-rate margin applicable to the loans by 0.50% if CRLLC s credit rating drops to the equivalent of a CCC+ or worse.

Amends the definition of Change of Control .

In February 2010, CRLLC launched a fourth amendment to its credit facility. Requisite approval was received by its lenders on March 11, 2010. The amendment, among other things, affords CRLLC the opportunity to issue junior lien debt, subject to certain conditions, including, but not limited to, a requirement that 100% of the proceeds are used to prepay the tranche D term loans. The amendment also affords CRLLC the opportunity to issue up to $350.0 million of first lien debt, subject to certain conditions, including, but not limited to, a requirement that 100% of the proceeds are used to prepay all of the remaining tranche D term loans.

The amendment provides financial flexibility to CRLLC through modifications to its financial covenants over the next four quarters and, if the initial issuance of junior lien debt occurs prior to March 31, 2011, the total leverage ratio becomes a first-lien only test and the interest coverage ratio is further modified. Additionally, the amendment permits CRLLC to re-invest up to $15.0 million of asset sale proceeds each year, so long as such proceeds are re-invested within twelve months of receipt (eighteen months if a binding agreement is entered into within twelve months). CRLLC will pay an upfront fee in an amount to equal 0.75% of the aggregate of the approving lenders loans and commitments outstanding as of March 11, 2010. Additionally, consenting lenders will also be paid an additional 0.25% consent fee on each of July 1, 2010, October 1, 2010 and January 1, 2011, if an initial issuance of junior lien debt is not completed by each of those respective dates. Additionally, CRLLC will pay a fee of $0.9 million in the first quarter of 2010 to a subsidiary of GS in connection with their services as lead bookrunner related to the amendment.

Under the terms of our credit facility, the interest-rate margin paid is subject to change based on changes in our credit rating by either S&P or Moody s. In February 2009, S&P placed the Company on negative outlook which resulted in an increase in our interest rate of 0.25% on amounts borrowed under our term loan facility, revolving credit facility and the funded letter of credit facility. In August 2009, S&P revised the Company s outlook to stable which resulted in a decrease in our interest rate by 0.25%, effective September 1, 2009, on amounts borrowed under our term loan facility, revolving credit facility and the funded letter of credit facility. As noted above, the Company terminated the funded letter of credit facility effective October 15, 2009.

The credit facility contains customary covenants, which, among other things, restrict, subject to certain exceptions, the ability of CRLLC 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 CRLLC may not enter into commodity agreements if, after giving effect thereto, the exposure under all such commodity agreements exceeds 75% of Actual Production

(the 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, CRLLC may not enter into material amendments related to any material rights under the Partnership s

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partnership agreement without the prior written approval of the requisite 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 CRLLC to maintain certain financial ratios as follows:

Fiscal Quarter Ending	Minimum Interest Coverage Ratio	Maximum Leverage Ratio
December 31, 2009 and thereafter	3.00:1.00	2.75:1.00

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 CRLLC consolidated net income (loss), 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 CRLLC 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, major scheduled turnaround expenses and for purposes of computing the financial ratios (and compliance therewith), the FIFO adjustment, and then subtracting certain items that increase consolidated net income. As of December 31, 2009, we were in compliance with our covenants under the credit facility.

We present CRLLC 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, CRLLC consolidated adjusted EBITDA is not a defined term under GAAP and should not be considered as an alternative to operating income or net income as a measure of operating results or as an alternative to cash flows as a measure of liquidity. CRLLC consolidated adjusted

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EBITDA is calculated under the credit facility as follows which reconciles CVR consolidated net income (loss) to CRLLC consolidated net income (loss) for the years presented below:

Consolidated Financial Results	Year Ended December 31, 2009	2008(2)	2007(2)
		(in millions)	
CVR net income (loss)	$ 69.4	$ 163.9	$ (67.6)
Plus:			
Selling, general and administrative at CVR	13.9	4.0	1.8
Interest expense			0.6
Loss on extinguishment of debt			0.7
Income tax expense (benefit)	29.2	63.9	(88.5)
Non-cash compensation expense for equity awards	1.8	(6.7)	
Unusual or nonrecurring charges		2.2	
Interest income		(0.1)	
Noncontrolling interest			(0.2)
CRLLC consolidated net income (loss)	114.3	227.2	(153.2)
Plus:			
Depreciation and amortization	84.9	82.2	68.4
Interest expense	44.2	40.3	60.5
Loss on extinguishment of debt	2.1	10.0	0.6
Letters of credit expenses and interest rate swap not included in interest expense	13.4	7.4	1.8
Major scheduled turnaround expense		3.3	76.4
Unrealized (gain) or loss on derivatives, net	37.8	(247.9)	113.5
Non-cash compensation expense for equity awards	3.3	(10.5)	25.0
(Gain) or loss on disposition of fixed assets		5.8	1.3
Unusual or nonrecurring charges	2.7	10.3	
Property tax increases due to expiration of abatement	10.9	11.6	
FIFO impact (favorable) unfavorable(1)	(50.9)	102.5	
Management fees			11.7
Goodwill impairment		42.8	
CRLLC consolidated adjusted EBITDA(2)	$ 262.7	$ 285.0	$ 206.0

(1) The second amendment to the credit facility entered into on December 22, 2008 amended the definition of consolidated adjusted EBITDA to add a FIFO adjustment. This amendment to the definition first applied for the year ending December 31, 2008 and applied through the quarter ending September 30, 2009. The third amendment to the credit facility entered into on October 2, 2009 permits CRLLC to continue to incorporate the FIFO adjustment at a reduced level of 75% into its financial covenant calculations through the remaining term of the credit facility.

(2) The 2008 and 2007 adjusted EBITDA amounts have been updated to incorporate the reconciliation of CVR consolidated net income (loss) to CRLLC consolidated net income (loss), for purposes of comparability to the

2009 CRLLC consolidated adjusted EBITDA.

In addition to the financial covenants previously mentioned, the credit facility restricts the capital expenditures of CRLLC and its subsidiaries to $80.0 million in 2010, and $50.0 million in 2011 and thereafter. The capital expenditures covenant includes a mechanism for carrying over the excess of any previous year s capital expenditure limit. The capital expenditures limitation will not apply for any fiscal year commencing with fiscal year 2009 if CRLLC obtains a total leverage ratio of less than or equal to 1.25:1.00 for any quarter

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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 $20.0 million, a breach or default with respect to material terms under other debt arrangements in an aggregate amount of at least $20.0 million which results in the debt becoming payable or declared due and payable before its stated maturity, events of bankruptcy, judgments and attachments exceeding $20.0 million, events relating to employee benefit plans resulting in liability in excess of $20.0 million, a change in control, the guarantees, collateral documents or the credit facility failing to be in full force and effect or being declared null and void, any guarantor repudiating its obligations, the failure of the collateral agent under the credit facility to have a perfected lien on any material portion of the collateral, 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, and if CVR incurs indebtedness, certain defaults with respect to such indebtedness.

The credit facility is subject to an intercreditor agreement between the lenders and J. Aron which deals with, among other things, voting, priority of liens, payments and proceeds of sale of collateral.

Payment Deferrals Related to Cash Flow Swap

As a result of the June/July 2007 flood and the temporary cessation of our operations on June 30, 2007, CRLLC 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. On October 11, 2008, J. Aron agreed to further defer these payments to July 31, 2009. At the time of the October 11, 2008 deferral, the outstanding balance was $72.5 million. In conjunction with the additional deferral of the remaining payments, we agreed to pay interest on the outstanding balance at the rate of LIBOR plus 2.75% until December 15, 2008 and LIBOR plus 5.00% to 7.50% (depending on J. Aron s cost of capital) from December 15, 2008 through the date of the payment. We also agreed to make prepayments of $5.0 million for the quarters ending March 31, 2009 and June 30, 2009. Additionally, we agreed that, to the extent CRLLC or any of its subsidiaries received net insurance proceeds related to the 2007 flood, the proceeds would be used to prepay the deferred amounts. The Goldman Sachs Funds and the Kelso Funds each guaranteed one half of the deferred payment obligations.

In January and February 2009, we prepaid $46.4 million of the deferred obligation, reducing the total principal deferred obligation to $16.1 million. On March 2, 2009, the remaining principal balance of $16.1 million was paid in full including accrued interest of $0.5 million resulting in CRLLC being unconditionally and irrevocably released from any and all of its obligations under the deferred agreements. In addition, J. Aron released the Goldman Sachs Funds and the Kelso Fund from any and all of their obligations to guarantee the deferred payment obligations.

Capital Spending

Our total capital expenditures for the year ended December 31, 2009 totaled $48.8 million, of which approximately $34.0 million was spent for the petroleum business, $13.4 million for the nitrogen fertilizer business and $1.4 million for corporate purposes. We divide our capital spending needs into two categories: non-discretionary and discretionary. Non-discretionary capital spending is required to maintain safe and reliable operations or to comply with

environmental, health and safety regulations. 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.

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The following table summarizes our total actual capital expenditures for 2009 and planned capital expenditures for 2010 by operating segment and major category (in millions):

	Year Ended December 31,	
	2009 Actual	2010 Budget
Petroleum Business:		
Environmental, safety and other	$ 2.3	$ 15.4
Ultra low sulfur gasoline (Tier II)	21.2	22.0
Sustaining	10.5	15.3
Petroleum business total capital excluding turnaround expenditures	34.0	52.7
Nitrogen Business:		
Environmental, safety and other	0.9	1.1
Sustaining	12.5	12.8
Nitrogen business total capital excluding turnaround expenditures	13.4	13.9
Corporate:	1.4	1.8
Total capital spending	$ 48.8	$ 68.4

In addition to the estimate of 2010 capital spending, as reflected in the above table, we expect to incur total major scheduled turnaround expenses of approximately $1.0 million for the petroleum business and approximately $3.8 million for the nitrogen fertilizer business.

Compliance with the Tier II gasoline required us to spend approximately $21.2 million in 2009 and we estimate that compliance will require us to spend approximately $22.0 million in 2010.

Our planned capital expenditures for 2010 are subject to change due to unanticipated increases in the cost, scope and completion time for our capital projects. For example, we may experience increases in labor and/or equipment costs necessary to comply with government regulations or to complete projects that sustain or improve the profitability of our refinery or nitrogen fertilizer plant. Capital spending for the nitrogen fertilizer business has been and will be determined by the managing general partner of the Partnership.

Cash Flows

The following table sets forth our cash flows for the periods indicated below:

	Year Ended December 31,		
	2009	2008	2007
	(in millions)		
Net cash provided by (used in)			

Operating activities	$ 85.3	$ 83.2	$ 145.9
Investing activities	(48.3)	(86.5)	(268.6)
Financing activities	(9.0)	(18.3)	111.3
Net increase (decrease) in cash and cash equivalents	$ 28.0	$ (21.6)	$ (11.4)

Cash Flows Provided by Operating Activities

Net cash flows from operating activities for the year ended December 31, 2009 was $85.3 million. The positive cash flow from operating activities generated over this period was primarily driven by $69.4 million of net income, favorable changes in other working capital and other assets and liabilities offset by unfavorable changes in trade working capital over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. For the year ended December 31, 2009, our net income

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was adversely impacted by both realized and unrealized losses of $55.2 million. Significant uses of cash for 2009 included the pay down of the J. Aron deferral totaling $62.4 million and the payment of $21.1 million for realized losses on the Cash Flow Swap. Partially offsetting the payments related to realized losses on the Cash Flow Swap was a cash receipt of $3.9 million related to the early termination of the Cash Flow Swap on October, 8, 2009 as well as additional insurance proceeds of $11.8 million. Other significant changes in working capital included a decrease of $12.1 million related to prepaid and other current assets and a decrease of $20.0 million of accrued income taxes. Trade working capital for the year-ended December 31, 2009 resulted in a use of cash of $133.9 million. This use of cash was the result of an inventory increase of $126.4 million, increased accounts receivable of $13.1 million, an increase in accounts payable by $0.7 million and the accrual of construction in progress of $5.0 million.

Net cash flows from operating activities for the year ended December 31, 2008 was $83.2 million. The positive cash flow from operating activities generated over this period was primarily driven by $163.9 million of net income, favorable changes in trade working capital and other assets and liabilities partially offset by unfavorable changes in other 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. Therefore, net income for the year ended December 31, 2008 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, 2008 (approximately one year and six months) and the NYMEX crack spread that is the basis for the underlying swaps had decreased, 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 $326.5 million decrease in the payable to swap counterparty. Other uses of cash from other working capital included $19.1 million from prepaid expenses and other current assets, $9.5 million from accrued income taxes and $7.4 million from deferred revenue and $5.3 million from other current liabilities, partially offset by a $74.2 million source of cash from insurance proceeds. Increasing our operating cash flow for the year ended December 31, 2008 was $88.1 million source of cash related to changes in trade working capital. For the year ended December 31, 2008, accounts receivable decreased $49.5 million and inventory decreased by $98.0 million resulting in a net source of cash of $147.5 million. These sources of cash due to changes in trade working capital were partially offset by a decrease in accounts payable, or a use of cash, of $59.4 million. Other primary sources of cash during the period include a $55.9 million 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, 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. 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. For the year ended December 31, 2007, our results included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2007 (approximately two years and six months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash Flow Swap significantly decreased our net income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $240.9 million increase in the payable to swap counterparty. Other sources of cash from other working capital included $4.8 million from prepaid expenses and other current assets, $27.0 million from other current liabilities and $20.0 million in insurance proceeds. Reducing our operating cash flow for the year ended December 31, 2007 was $42.9 million use of cash related to changes in trade working capital. For the year ended December 31, 2007, accounts receivable increased $17.0 million and inventory increased by $85.0 million resulting in a net use of cash of $102.0 million. These uses of cash due to changes in trade working capital were partially offset by an increase in accounts payable, or a source of cash, of $59.1 million. Other primary uses of cash during the period include a $105.3 million increase in our insurance receivable related to the June/July 2007 flood and a $57.7 million use of cash related to deferred income taxes primarily the result of the unrealized loss on the Cash Flow Swap.

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Cash Flows Used In Investing Activities

Net cash used in investing activities for the year ended December 31, 2009 was $48.3 million compared to $86.5 million for the year ended December 31, 2008. The decrease in investing activities for the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily the result of reduced capital expenditures associated with various completed capital projects in our petroleum business in 2008.

Net cash used in investing activities for the year ended December 31, 2008 was $86.5 million compared to $268.6 million for the year ended December 31, 2007. The decrease in investing activities for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was the result of decreased capital expenditures associated with various capital projects in our petroleum business.

Cash Flows Used In Financing Activities

Net cash used in financing activities for the year ended December 31, 2009 was $9.0 million as compared to net cash used by financing activities of $18.3 million for the year ended December 31, 2008. The primary uses of cash for the year ended December 31, 2009 were $4.8 million of scheduled principal payments in long-term debt and $4.0 million for the payment of financing costs associated with the amendment to our outstanding credit facility. The primary uses of cash for the year ended December 31, 2008 were an $8.5 million payment for financing costs, $4.8 million of scheduled principal payments in long-term debt retirement and $4.0 million related to deferred costs associated with the abandoned initial public offering of the Partnership and CVR Energy s proposed convertible debt offering.

Net cash used in financing activities for the year ended December 31, 2008 was $18.3 million as compared to net cash provided by financing activities of $111.3 million for the year ended December 31, 2007. The primary uses of cash for the year ended December 31, 2008 were an $8.5 million payment for financing costs, $4.8 million of scheduled principal payments in long-term debt retirement and $4.0 million related to deferred costs associated with the abandoned initial public offering of the Partnership and CVR Energy s proposed convertible debt offering. 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 were $335.8 million of long-term debt retirement and $2.5 million in payments of financing costs.

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, 2009 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, 2009 and thereafter.

	Payments Due by Period						
	Total	2010	2011	2012	2013	2014	Thereafter
	(in millions)						
Contractual Obligations							
Long-term debt(1)	$ 479.5	$ 4.8	$ 4.7	$ 4.7	$ 465.3	$	$
Operating leases(2)	21.6	5.4	5.4	5.0	2.6	1.9	1.3
Capital lease obligation(3)	4.4	4.4					
Unconditional purchase obligations(4)(5)	300.5	32.1	30.5	27.7	27.8	27.8	154.6

Environmental liabilities(6)	5.8	2.2	0.4	0.4	0.3	0.4	2.1
Interest payments(7)	148.5	41.1	40.6	40.4	26.4		
Total	$ 960.3	$ 90.0					