CVR ENERGY INC
Form 10-K
March 13, 2009

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, 2008**
	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 *(State or Other Jurisdiction of Incorporation or Organization)*	**61-1512186** *(I.R.S. Employer Identification No.)*
2277 Plaza Drive, Suite 500 **Sugar Land, Texas** *(Address of Principal Executive Offices)*	**77479** *(Zip Code)*

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

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, $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 Exchange Act. Yes o No þ

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

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

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

The 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, 2008 (the last day of the registrant s second fiscal quarter) was $443,002,175.

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, 2009
Common Stock, par value $0.01 per share	86,243,745 shares

Documents Incorporated By Reference

Document	Parts Incorporated
Proxy Statement for the 2009 Annual Meeting of Stockholders	Items 10, 11, 12, 13 and 14 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 heating oil.

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, FCC unit 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 or to be 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.

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 diesel fuel.

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.

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 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.

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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: a measure of energy. One Btu of heat is required to raise the temperature of one pound of water one degree Fahrenheit.

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.

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 UAN is 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 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 and other feedstocks.

PART I

Item 1. *Business*

CVR Energy, Inc. and, unless the context otherwise requires, its subsidiaries (CVR Energy , the Company , we , us , our) is an independent refiner and marketer of high value transportation fuels. In addition, we currently own all of the interests (other than the managing general partner interest and associated incentive distribution rights (the IDRs)) in 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 refinery in Coffeyville, Kansas. In addition, our supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma, western Missouri, eastern Colorado and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of 1.2 million barrels and (4) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and to customers at throughput terminals on Magellan refined products distribution systems. Additionally, we lease 2.7 million barrels of storage capacity at Cushing, Oklahoma.

The nitrogen fertilizer business consists of a nitrogen fertilizer manufacturing facility comprised of (1) a 1,225 ton-per-day ammonia unit, (2) a 2,025 ton-per-day UAN unit and (3) an 84 million standard cubic foot per day gasifier complex. The nitrogen fertilizer business is the only operation in North America that utilizes a coke gasification process to produce ammonia (based on data provided by Blue Johnson & Associates). 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).

We have two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2008, 2007 and 2006, we generated combined net sales of $5.0 billion, $3.0 billion and $3.0 billion, respectively, and operating income of $148.7 million, $186.6 million and $281.6 million, respectively. Our petroleum business generated $4.8 billion, $2.8 billion and $2.9 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 $31.9 million, $144.9 million and $245.6 million of our combined operating income, respectively, with the nitrogen fertilizer business contributing substantially all of the remainder.

Our History

Our refinery assets, which began operation in 1906, and the nitrogen fertilizer plant, which was built in 2000, were operated as a component 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 and completed the purchase of these assets on March 3, 2004. Coffeyville Group Holdings, LLC operated our business from March 3, 2004 through June 24, 2005.

On June 24, 2005, pursuant to a stock purchase agreement dated May 15, 2005, Coffeyville Acquisition LLC (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. Prior to CVR Energy s initial public offering in October 2007, (1) CALLC transferred all of its businesses to CVR Energy in exchange for all of CVR Energy s common stock, (2) CALLC was effectively split into two entities, with the Kelso Funds controlling CALLC

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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, (3) we transferred our nitrogen fertilizer business into the Partnership in exchange for all of the partnership interests in the Partnership and (4) 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.

Petroleum Business

We operate a 115,000 bpd complex cracking and coking medium-sour oil refinery. This amount 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, 2008, our refinery s product yield included gasoline (mainly regular unleaded) (48%), diesel fuel (mainly ultra low sulfur diesel) (41%), and coke and other refined products such as NGC (propane, butane), slurry, reformer feeds, sulfur, gas oil and produced fuel (11%).

Our petroleum business also includes the following auxiliary operating assets:

> *Crude Oil Gathering System.* We own and operate a crude oil gathering system serving central Kansas, northern 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 over 300 miles of feeder and trunk pipelines, 54 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 business grew by 27% to nearly 26,000 barrels per day in 2008 compared to 2007. Gathered crude oil provides a base supply of feedstock for our refinery and serves as an attractive alternative to higher priced foreign sweet crude oil.
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> *Phillipsburg Terminal.* We own storage and terminalling facilities for asphalt and refined fuels 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.
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> *Pipelines.* We own a 145,000 bpd proprietary pipeline system that transports crude oil from Caney, Kansas to our refinery. Crude oils sourced outside of our proprietary gathering system are delivered by common carrier pipelines into various terminals in Cushing, Oklahoma, where they are blended and then delivered to Caney, Kansas via a pipeline owned by Plains All American L.P. (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 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 in an economic manner; greater complexity makes a refinery more profitable. As a result of key investments in our refining assets, our refinery s complexity has increased from 10.3 to 12.1, and we have achieved significant increases in our refinery crude oil throughput rate over historical levels.

Feedstocks Supply

Our refinery has the capability to process blends of a variety of crudes ranging from heavy sour to light sweet crude oil. Currently, our refinery processes crude oil from a broad array of sources. We purchase 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 isobutene, normal butane, natural gasoline, alky feed, naptha, gas oil and vacuum tower bottoms.

Crude is supplied to our refinery through our wholly owned gathering system and by pipeline. We increased the number of barrels of crude oil supplied through our crude gathering system in 2008 and now supply in excess of 24,000 bpd of crude to the refinery (approximately 23% of total supply). Locally produced crudes are delivered to the refinery at a discount to WTI, and although slightly heavier and more sour, offer good economics to the refinery. These crudes are light and sweet enough to allow us to blend higher percentages of low cost crudes such as heavy sour Canadian while maintaining our target medium sour blend with an API gravity of 28-36 degrees and 0.9-1.2% sulfur. Crude oils sourced outside of our proprietary gathering system are delivered to Cushing, Oklahoma by various pipelines including Seaway, Basin and Spearhead and subsequently to Coffeyville via the Plains pipeline and our own 145,000 bpd proprietary pipeline system.

For the year ended December 31, 2008, our crude oil supply blend was comprised of approximately 73% light sweet crude oil, 11% heavy sour crude oil and 16% medium/light sour crude oil. The light sweet crude oil includes our locally gathered crude oil.

For 2008, we obtained all of the crude oil for our refinery (other than crude oil that we acquired in Kansas, Missouri, Nebraska, Oklahoma and all states adjacent thereto, and North Dakota) under a credit intermediation agreement with J. Aron & Company (J. Aron). This agreement expired on December 31, 2008, and a new crude oil supply agreement was entered into with Vitol Inc. (Vitol) effective December 31, 2008 for an initial term of two years. Crude oil intermediation agreements help 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 oil 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 refined products distribution systems. In the year ended December 31, 2008, approximately 34% of the refinery s products were sold through the rack system directly to retail and wholesale customers while the remaining 66% 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 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, 2008, QuikTrip Corporation accounted for 13% of our petroleum business sales and 64% of our petroleum sales were made to our ten largest customers. We sell bulk products based on industry market related indices such as Platt s or the New York Mercantile Exchange (NYMEX) related Group Market (Midwest) prices. Through our rack marketing division, the rack sales are at daily posted prices which are influenced by the NYMEX, competitor pricing and group spot market differentials.

Competition

We compete with our competitors primarily on the basis of price, reliability of supply, availability of multiple grades of products and location. The principal competitive factors affecting our refining operations are cost of crude oil and other feedstock costs, refinery complexity (a measure of a refinery s ability to convert lower cost heavy and sour crudes into greater volumes of higher valued refined products such as gasoline and distillate), refinery efficiency, refinery product mix and product distribution and transportation costs. 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

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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.

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 vary demand for gasoline and diesel fuel.

Nitrogen Fertilizer Business

The nitrogen fertilizer business operates the only nitrogen fertilizer plant in North America that utilizes a pet coke gasification process to generate hydrogen feedstock that is further converted to ammonia for the production of nitrogen fertilizers. The nitrogen fertilizer business has indefinitely suspended any further development related to the previously announced UAN fertilizer plant expansion.

Raw Material Supply

The nitrogen fertilizer facility s primary input is pet coke. During the past five years, more than 77% 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, which is one step in refining crude oil into gasoline, diesel and jet fuel. In order to refine heavy crude oils, which are lower in cost and more prevalent than higher quality crude, refiners use coker units, which help to reduce the sulfur content in fuels refined from heavy or sour crude oil. In North America, the shift from refining dwindling reserves of sweet crude oil to more readily available heavy and sour crude (which can be obtained from, among other places, the Canadian oil sands) will result in increased pet coke production.

The nitrogen fertilizer business fertilizer plant is located in Coffeyville, Kansas, which is part of the Midwest coke market. The Midwest coke market is not subject to the same level of pet coke price variability as is the Gulf Coast coke market, due mainly to more stable transportation costs. Pet coke transportation costs have gone up substantially in both the Atlantic and Pacific sectors. Given the fact that the majority of the nitrogen fertilizer business coke suppliers are located in the Midwest, the nitrogen fertilizer business geographic location gives it a significant freight cost advantage over its Gulf Coast coke market competitors. The Midwest Green Coke (Chicago Area, FOB Source) annual average price over the last three years has ranged from $25.50 to $34.33 per ton. The U.S. Gulf Coast market annual average price during the same period has ranged from $41.50 to $79.18 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 air separation plant has not experienced any long-term operating problems. The nitrogen fertilizer plant has business interruption insurance for up to $50 million in case of any interruption in the supply of oxygen from Linde from a covered peril. The agreement with Linde expires in 2020. The agreement also provides that if the nitrogen fertilizer business requirements for liquid or gaseous oxygen, liquid or gaseous nitrogen or clean dry air exceed specified instantaneous flow rates by at least 10%, the nitrogen fertilizer business can solicit bids from Linde and third parties to supply its incremental product needs. The nitrogen fertilizer business is required to provide notice to Linde of the approximate quantity of excess product that it will need and the approximate date by which it will need it; the nitrogen fertilizer business and Linde will then jointly develop a request for proposal for soliciting bids from third parties and Linde. The bidding procedures may be limited under specified circumstances.

The nitrogen fertilizer business imports start-up steam for the nitrogen fertilizer plant from our oil refinery, and then exports steam back to the oil refinery once all units in the nitrogen fertilizer plant are in service. 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 1,300 tons per day of pet coke from our oil refinery and third-party sources and converting it into approximately 1,200 tons per day of ammonia. A majority of the ammonia is converted to approximately 2,000 tons per day of UAN. Typically 0.41 tons of ammonia 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 small fill volumes that move in the off-season to fill available storage at the dealer level.

Ammonia and UAN are distributed by truck or by railcar. If delivered by truck, products are sold on 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 utilize these assets to deliver products. The nitrogen fertilizer business owns all of the truck and rail loading equipment at our nitrogen fertilizer facility. The nitrogen fertilizer business operates two truck loading and eight rail loading racks for each of ammonia and UAN.

The nitrogen fertilizer business markets agricultural products to destinations that produce the best margins for the business. These markets are primarily located near the Union Pacific Railroad lines or destinations that can be supplied by truck. By securing this business directly, the nitrogen fertilizer business reduces its dependence on distributors serving the same customer base, which enables the nitrogen fertilizer business to capture a larger margin and allows it to better control its product distribution. Most of the agricultural sales are made on a competitive spot basis. The nitrogen fertilizer business also offers products on a prepay basis for in-season demand. The heavy in-season demand periods are spring and fall in the corn belt and summer in the wheat belt. 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.

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Customers

The nitrogen fertilizer business sells ammonia to agricultural and industrial customers. The nitrogen fertilizer business sells approximately 80% of the ammonia it produces to agricultural customers in the mid-continent area between North Texas and Canada, and approximately 20% to industrial customers. Agricultural customers include distributors such as MFA, United Suppliers, Inc., Brandt Consolidated Inc., Gavilon Fertilizers 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.

For the years ended December 31, 2008, 2007 and 2006, the top five ammonia customers in the aggregate represented 54.7%, 62.1% and 51.9% of the nitrogen fertilizer business ammonia sales, respectively, and the top five UAN customers in the aggregate represented 37.2%, 38.7% and 30.0% of the nitrogen fertilizer business UAN sales, respectively. 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. During the year ended December 31, 2006, Brandt Consolidated Inc. and MFA accounted for 22.2% and 13.1% of its ammonia sales, respectively, and Gavilon Fertilizers LLC and CHS Inc. accounted for 8.4% and 6.8% of its UAN sales, respectively.

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 2008 represented approximately 4.6% 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.

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, New Source Review, and Leak Detection and Repair. We have incurred, and expect to continue to incur, substantial capital expenditures to maintain compliance with these and other air emission regulations that have been promulgated or may be promulgated or revised in the future.

In March 2004, we 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 oil refinery. Under the Consent Decree, we agreed to install controls on certain process equipment and make certain operational changes at our refinery. As a result of our agreement to install certain controls and implement certain operational changes, the EPA and KDHE agreed not to impose civil penalties, and provided a release from liability for Farmland s alleged noncompliance with the issues addressed by the Consent Decree. Among other control measures and operational changes, the Consent Decree requires us to install controls to minimize both SO_2 and nitrogen oxides (NOx) emissions by January 1, 2011. In addition, pursuant to the Consent Decree, we assumed certain cleanup obligations at the Coffeyville refinery and the

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Phillipsburg terminal. The cost of complying with the Consent Decree is expected to be approximately $53 million, of which approximately $47 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.

Over the course of the last several years, the EPA 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 many 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 all refiners to enter into global settlements pertaining to all marquee issues. Our current Consent Decree covers some, but not all, of the marquee issues. The Company has 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 settlement agreement with the EPA. To the extent that we were to agree to enter a global settlement, we believe 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.

The nitrogen fertilizer facility experienced an ammonia release as a result of a malfunction in August 2007 and reported the excess ammonia emissions to the EPA and KDHE. The EPA investigated the release and we provided requested data to the EPA pursuant to their request. Our incident investigation related to the release indicates that the malfunction could not have been reasonably anticipated or avoided and we have forwarded our results to the EPA. As a result of an inspection by the Occupational Safety and Health Administration (OSHA) following the August 2007 ammonia release OSHA issued citations against both the refinery and the nitrogen fertilizer facility. These citations were settled for $163,000 and none of the citations were classified as serious.

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 would defer 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 $38 million during 2008, approximately $103 million during 2007 and $133 million during 2006, and we estimate that compliance will require us to spend approximately $52 million between 2009 and 2011.

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 and we agreed to meet the final ULSG annual average standard in 2010. We met the required sulfur standards under our hardship waiver for 2008, and expect to be able to comply with the remaining requirements of our hardship waiver.

Greenhouse Gas Emissions

It is probable that Congress will adopt some form of federal mandatory greenhouse gas emission reductions legislation or regulation in the near future, although the specific requirements of any such legislation are uncertain at this time. In addition, the EPA could begin regulating greenhouse gas emissions as air pollutants under the federal Clean Air Act. 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 Accord, which calls for the development of a cap-and-trade system to control greenhouse gas emissions and for the inventory of such emissions. However, the individual states that have signed on to the accord must adopt laws or regulations implementing the trading scheme before it becomes effective, and the timing and specific requirements of any such laws or regulations in Kansas are uncertain at this time.

Compliance with any future legislation or regulation of greenhouse gas emissions, if it occurs, may result in increased compliance and operating costs and may have a material adverse effect on our results of operations, financial condition, and the ability of the nitrogen fertilizer business to make distributions.

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 $3.3 million in financial assurance for closure/post-closure care for hazardous waste management units at the Phillipsburg terminal and the Coffeyville refinery.

Impacts of Past Manufacturing. We are subject to a 1994 EPA administrative order related to investigation of possible past releases of hazardous materials to the environment at the Coffeyville refinery. In accordance with the order, we have documented existing soil and ground water conditions, which require investigation or remediation projects. The Phillipsburg terminal is subject to a 1996 EPA administrative order related to investigation of possible past releases of hazardous materials to the environment at the Phillipsburg terminal, which operated as a refinery until 1991. The Consent Decree that we signed with the EPA and KDHE requires us to complete all activities in accordance with federal and state rules.

The anticipated remediation costs through 2012 were estimated, as of December 31, 2008, to be as follows (in millions):

Facility	Site Investigation Costs	Capital Costs	Total O&M Costs	Total Estimated Costs

			Through 2012	**Through 2012**
Coffeyville Oil Refinery	$ 0.2	$	$ 1.0	$ 1.2
Phillipsburg Terminal	0.4		1.7	2.1
Total Estimated Costs	$ 0.6	$	$ 2.7	$ 3.3

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 2009, we will spend $5.0 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 $1.2 million in 2008 associated with related remediation.

Financial Assurance. We were required in the Consent Decree to establish financial assurance to cover the projected cleanup costs posed by the Coffeyville and Phillipsburg facilities in the event we failed to fulfill our clean-up obligations. In accordance with the Consent Decree, this financial assurance is currently provided by a bond 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 release occurred, any persons who owned or operated the property when the release occurred, and any persons who disposed of, or arranged for the transportation or disposal of, hazardous substances at a contaminated property. Liability under CERCLA is strict, retroactive and joint and several, so that any responsible party may be held liable for the entire cost of investigating and remediating the release of hazardous substances. 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. We measure our success in the personal safety and health area primarily through the use of injury frequency rates administered by OSHA. In 2008, our oil refinery experienced a 14% increase in injury frequency rates and the nitrogen fertilizer plant experienced a 22% reduction in such rate as compared to the average of the previous three years. The recordable injury rate reflects the number of recordable incidents (injuries as defined by OSHA) per 200,000 hours worked. For the year ended December 31, 2008, we had a recordable injury rate of 1.30 in our petroleum business and 2.53 in the nitrogen fertilizer business. Our recordable injury rate for all business units was 1.12 for 2008. In November 2008, refinery employees reached a company record by working more than 1 million hours without a lost-time accident. Our transportation group has worked three years without a lost time accident. Despite our efforts to achieve excellence in our safety and health performance, there can be no assurances that there will not be accidents resulting in injuries or even fatalities.

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 during the fourth quarter of 2008. We do not believe any fines or penalties that could be imposed as a result of the inspections would be material to our results of operation. Additionally, we are not currently aware of any significant capital expenditures that we will be required to make as a result of the inspection.

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Employees

As of December 31, 2008, 475 employees were employed in our petroleum business, 120 were employed by the nitrogen fertilizer business and 59 employees were employed at our offices in Sugar Land, Texas and Kansas City, Kansas.

We entered into collective bargaining agreements which as of December 31, 2008 cover approximately 38% of our employees (all of whom work in our petroleum business) 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 agreement was reached with the Metal Trade Unions effective August 31, 2008. No substantial changes were made to the agreement. The new agreement will now expire in March 2013. A new agreement was reached with the United Steelworkers on March 3, 2009. There were no substantial changes to the agreement which will now expire 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, Forms 3, 4 and 5 filed by our executive officers, directors and 10% stockholders, and all amendments to those reports, are available free of charge through our website, 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 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, 2008 (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

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

Our petroleum business financial results are primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil and other feedstocks. Future volatility in refining industry margins may cause 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.

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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 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, 2008, we had cash and cash equivalents of $8.9 million and $100.1 million available under our revolving credit facility. In the current volatile crude oil environment, working capital is subject to substantial variability from week-to-week and month-to-month.

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. In the first three quarters of 2008 we experienced extremely high oil prices which substantially increased our short-term working capital needs. Our long-term capital needs include capital expenditures we are required to make to comply with Tier II gasoline standards and the Consent Decree. Compliance with Tier II gasoline standards will require us to spend approximately $52 million between 2009 and 2011. The overall costs of complying with the Consent Decree are expected to be approximately $53 million, of which approximately $47 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. 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 intermediation 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 a crude oil intermediation agreement with Vitol, which became effective on December 31, 2008 for an initial term of two years. The crude oil intermediation 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 is refined and the yielded products are sold. If we were required to obtain our crude supply without the benefit of an intermediation agreement, our exposure to crude 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.

Our refinery requires approximately 85,000 to 100,000 bpd of crude oil in addition to the crude oil we gather locally in Kansas, Oklahoma, Colorado, Missouri, and Nebraska. We obtain a portion of our non-gathered crude oil, approximately 18% in 2008, from foreign sources such as Latin America, South America, the Middle East, West Africa, Canada and the North Sea. The actual amount of foreign crude oil we purchase is dependent on market conditions and will vary from year to year. We are subject to the political, geographic, and economic risks attendant to doing business with suppliers located in those regions. Disruption of production in any of such regions for any reason could have a material impact on other regions and our business. In the event that one or more of our traditional suppliers becomes unavailable to us, we may be unable to obtain an adequate supply of crude oil, or we may only be able to obtain our crude oil supply at unfavorable prices. As a result, we may experience a reduction in our liquidity and our results of operations could be materially adversely affected.

Severe weather, including hurricanes along the U.S. Gulf Coast, could interrupt our supply of crude oil. Supplies of crude oil to our refinery are periodically shipped from U.S. Gulf Coast production or terminal facilities, including through the Seaway Pipeline from the U.S. Gulf Coast to Cushing, Oklahoma. U.S. Gulf Coast facilities could be subject to damage or production interruption from hurricanes or other severe weather in the future which could interrupt or materially adversely affect our crude oil supply. If our supply of crude oil is interrupted, our business, financial condition and results of operations could be materially adversely impacted.

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.

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 regulations, technological advances, consumer demand, improved pricing or otherwise, the greater the impact on pricing and demand for our products and our profitability. There are presently significant governmental and consumer pressures to increase the use of alternative fuels in the United States.

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

Changes in our credit profile may affect the way crude oil suppliers view our ability to make payments and may induce them to shorten the payment terms of their invoices. Given the large dollar amounts and

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volume of our feedstock purchases, a change in payment terms may have a material adverse effect on our liquidity and our ability to make payments to our suppliers.

Risks Related to the Nitrogen Fertilizer Business

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

Because most nitrogen fertilizer manufacturers rely on natural gas as their primary feedstock, and the cost of natural gas is a large component (approximately 90% based on historical data) of the total production cost of nitrogen fertilizers for natural gas-based nitrogen fertilizer manufacturers, the price of nitrogen fertilizers has historically generally correlated with the price of natural gas. The nitrogen fertilizer business does not hedge against declining natural gas prices. Any decline in natural gas prices could have a material adverse impact on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make distributions.

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

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

A significant portion of nitrogen fertilizer product sales 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, or an inability of the nitrogen fertilizer business to make distributions to us.

Nitrogen fertilizer products are commodities, the price of which can be volatile. The prices of nitrogen fertilizer products depend on a number of factors, including general economic conditions, cyclical trends in end-user markets, competition, supply and demand imbalances, and weather conditions, which have a greater relevance because of the seasonal nature of fertilizer application.

A major factor underlying the current level of demand for nitrogen-based fertilizer products is the expanding production of ethanol in the United States and the expanded use of corn in ethanol production. Ethanol production in the United States is highly dependent upon a myriad of federal and state legislation and regulations, and is made significantly more competitive by various federal and state incentives, including tariffs on imported ethanol. Recent studies showing that expanded ethanol production may increase the level of greenhouse gases in the environment may reduce political support for ethanol production. The elimination or significant reduction in ethanol incentive programs could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make distributions.

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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 the ability of the nitrogen fertilizer business to make distributions.

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.

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

Pet coke is a key raw material used by the nitrogen fertilizer business in the manufacture of nitrogen fertilizer products. Increases in the price of pet coke could have a material adverse effect on the nitrogen fertilizer business results of operations, financial condition and ability to make cash distributions. Moreover, if pet coke prices increase the nitrogen fertilizer business may not be able to increase its prices to recover increased pet coke costs, because market prices for the nitrogen fertilizer business nitrogen fertilizer products are generally correlated with natural gas prices, the primary raw material used by competitors of the nitrogen fertilizer business, and not pet coke prices. Based on the nitrogen fertilizer business current output, the nitrogen fertilizer business obtains most (over 77% on average during the last five years) of the pet coke it needs from our adjacent oil refinery, and procures the remainder on the open market. The nitrogen fertilizer business competitors are not subject to changes in pet coke prices. The nitrogen fertilizer business is sensitive to fluctuations in the price of pet coke on the open market. Pet coke prices could significantly increase in the future. The nitrogen fertilizer business might also be unable to find alternative suppliers to make up for any reduction in the amount of pet coke it obtains from our oil refinery.

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

The nitrogen fertilizer business relies on third party suppliers, including Linde, which owns an air separation plant that provides oxygen, nitrogen and compressed dry air to its gasifier 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 obligation could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

The nitrogen fertilizer 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

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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 our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions. We are currently engaged in litigation with the City of Coffeyville with respect to the pricing they are charging to provide us with electricity.

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

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

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 Partnership or us being named as a defendant in lawsuits asserting claims for large amounts of damages, which could have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make distributions.

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

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

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

These transportation operations, equipment and services are also subject to environmental, safety, and regulatory oversight. Due to concerns related to terrorism or accidents, local, state and federal governments

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could implement new regulations affecting the transportation of the nitrogen fertilizers business products. In addition, new regulations could be implemented affecting the equipment used to ship its products.

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

Risks Related to Our Entire Business

Unprecedented 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 have been experiencing extreme volatility and disruption. The volatility and disruption have reached unprecedented levels. 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. 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, 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.

The turmoil in the global economy may also impact our business, financial condition and results of operations in ways we cannot currently predict.

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 the ability of the nitrogen fertilizer business to make cash distributions. In addition, a major accident, fire, flood, crude oil discharge or other event could damage our facilities or the environment and the surrounding community or result in injuries or loss of life.

For example, the flood that occurred during the weekend of June 30, 2007 shut down our refinery for seven weeks, shut down the nitrogen fertilizer facility for approximately two weeks and required significant expenditures to repair damaged equipment.

If our facilities experience a major accident or fire or other event or an interruption in supply or operations, our business could be materially adversely affected if the damage or liability exceeds the amounts of business interruption, property, terrorism and other insurance that we benefit from or maintain against these risks and successfully collect. As required under our existing credit facility, we maintain property and business interruption insurance capped at $1.0 billion that is subject to various deductibles and sub-limits for particular types of coverage (e.g., $200 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 cannot be claimed because it was lost within 45 days after the start of the flood.

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

The energy industry is highly capital intensive, and the entire or partial loss of individual facilities can result in significant costs to both industry participants, such as us, and their insurance carriers. In recent years, several large energy industry claims have resulted in significant increases in the level of premium costs and deductible periods for participants in the energy industry. For example, during 2005, Hurricanes Katrina and Rita caused significant damage to several petroleum refineries along the U.S. Gulf Coast, in addition to numerous oil and gas production facilities and pipelines in that region. As a result of large energy industry 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.

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

In June 2005, CALLC entered into the Cash Flow Swap, which is not subject to margin calls, in the form of three swap agreements with J. Aron for the period from July 1, 2005 to June 30, 2010. These agreements were subsequently assigned from CALLC to CRLLC on June 24, 2005. Based on crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 57% and 14% of crude oil capacity for the periods January 1, 2009 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we may terminate the Cash Flow Swap in 2009 or 2010, at which time any unrealized loss will become a fixed obligation. Otherwise, under the terms of our credit facility, management has limited discretion to change the amount of hedged volumes under the Cash Flow Swap therefore affecting our exposure to market volatility. As a result, the Cash Flow Swap, under which payments are calculated based on crack spreads in absolute terms, has had and may continue to have a material negative impact on our earnings. In addition, because this derivative is based on NYMEX prices while our revenue is based on prices in the Coffeyville supply area, the contracts do not eliminate all of the risk of price volatility. If the price of products on NYMEX is different from the value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product that is contracted in the swap.

If we enter into derivative transactions in the future we could incur significant losses.

In addition, as a result of the accounting treatment of these contracts, unrealized gains and losses are charged to our earnings based on the increase or decrease in the market value of the unsettled position and the inclusion of such derivative gains or losses in earnings may produce significant period-to-period earnings volatility that is not necessarily reflective of our underlying operational performance. The positions under the Cash Flow Swap resulted in unrealized gains (losses) of $253.2 million and ($103.2) million for the years ended December 31, 2008 and 2007, respectively. As of December 31, 2008, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $17.7 million change to the fair value of derivative commodity position and would impact the gain (loss) on derivatives, net on the Consolidated Statements of Operations by the same amount. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies Derivative Instruments and Fair Value of Financial Instruments.

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 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. Depending on the underlying facts and circumstances, we could be held strictly 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, we entered into a Consent Decree to address certain allegations of Clean Air Act violations by Farmland at the Coffeyville oil refinery in order to address the alleged violations and eliminate liabilities going forward. The costs of complying with the Consent Decree is expected to be approximately $53 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 Impacts of Past Manufacturing. To date, we have materially complied with the Consent Decree and we have not had to pay any stipulated penalties, which are required to be paid for failure to comply with various terms and conditions of the Consent Decree. 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 oil refinery and the Phillipsburg terminal (which operated as a refinery until 1991), have environmental contamination. We have assumed Farmland s responsibilities under certain RCRA 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 extensive soil and groundwater investigation and sampling programs arise in the areas where we have assumed liability for the corrective action, that liability could have a material adverse effect on our results of operations and financial condition and may not be covered by insurance.

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 ability of the nitrogen fertilizer business to make cash distributions.

Greenhouse gas emissions may be the subject of federal or state legislation or regulated in the future as an air pollutant.

Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of discussion or implementation. These include proposed federal legislation and regulation and state actions to develop statewide or regional programs, which would require reductions in greenhouse gas emissions. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any greenhouse gas emissions program. These actions could also impact the consumption of refined products, thereby affecting our refinery operations. Compliance with any future legislation or regulation of greenhouse gas emissions, if it occurs, may result in increased compliance and operating costs and may have a material adverse effect on our results of operations, financial condition and the ability of the nitrogen fertilizer business to make cash distributions.

We are subject to strict laws and regulations regarding employee and process safety, and failure to comply with these laws and regulations could have a material adverse effect on our results of operations, financial condition and 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 ability of the nitrogen fertilizer business to make distributions 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 46.2% of our petroleum sales for the year ended December 31, 2008. Further in the aggregate, the top five ammonia customers of the nitrogen fertilizer business represented 54.7% of its ammonia sales for the year ended December 31, 2008 and the top five UAN customers of the nitrogen fertilizer business represented 37.2% 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 ability of the nitrogen fertilizer business to make distributions.

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, 2008, we had total term debt outstanding of $484.3 million, $49.9 million in letters of credit outstanding and borrowing availability of $100.1 million under our credit facility. We and our subsidiaries may be able to incur significant additional indebtedness in the future. If new indebtedness is added to our current indebtedness, the risks described below could increase. Our high level of indebtedness could have important consequences, such as:

- limiting our ability to obtain additional financing to fund our working capital, acquisitions, expenditures, debt service requirements or for other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service debt;
- limiting our ability to compete with other companies who are not as highly leveraged;

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

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

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

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

In addition, borrowings under our 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 costs are also effected by our credit ratings. Standard & Poor s decision in February 2009 to place us on a negative outlook resulted in an increase in our interest rate of 0.25%. If our credit ratings further decline in the future, the interest rates we are charged on debt under our credit facility could increase up to another 0.25% from their rate as of March 1, 2009. Our interest expense for the year ended December 31, 2008 was $40.3 million. A 1% increase or decrease in the applicable interest rates under our credit facility, using average debt outstanding at December 31, 2008, would correspondingly change our interest expense by approximately $4.9 million per year.

In addition, changes in our credit ratings may affect the way crude oil suppliers view our ability to make payments and may induce them to shorten the payment terms of their invoices. Given the large dollar amounts and volume of our feedstock purchases, a change in payment terms may have a material adverse effect on our 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, 2008, approximately 38% of our employees, all of whom work in our petroleum business, were represented by labor unions under collective bargaining agreements. Effective August 31, 2008, a new agreement was reached with the Metal Trades Unions, which will now expire in March 2013. A new agreement also was reached with the United Steelworkers on March 3, 2009. The new agreement is now scheduled to expire in March 2012. 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.

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.

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

We are subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act) and the corporate governance standards of the Sarbanes-Oxley Act of 2002, as amended (the Sarbanes-Oxley Act). These requirements may place a strain on our management, systems and resources. The Exchange Act requires that we file annual, quarterly and current reports with respect to our business and financial condition. The Sarbanes-Oxley Act requires, among other things, that we maintain effective disclosure controls and procedures and internal control over financial reporting and that management annually assess the effectiveness of our internal control over financial reporting.

If we fail to maintain the adequacy of our internal control over financial reporting, as such standards are modified, supplemented or amended from time to time; we may not be able to ensure that we can conclude on an ongoing basis that we have effective internal control over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act. Failure to achieve and maintain an effective internal control environment could cause us to incur substantial expenditures of management time and financial resources to identify and correct any such failure. We could also suffer a loss of confidence in the reliability of our financial statements if our independent registered public accounting firm reports a material weakness in our internal controls, if we do not maintain effective controls and procedures or if we are otherwise unable to deliver timely and reliable financial information. Any loss of confidence in the reliability of our financial statements or other negative reaction to our failure to maintain adequate disclosure controls and procedures or internal controls could results in a decline in the price of our common stock. In addition, if we fail to remedy any material weakness, our financial statements may be inaccurate, we may face restricted access to the capital markets and the price of our common stock may be adversely affected.

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

A company of which more than 50% of the voting power is held by an individual, a group or another company is a controlled company within the meaning of the New York Stock Exchange (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 with a written charter addressing the committee s purpose and responsibilities; and

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

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We are relying on all of these exemptions as a controlled company, except that our nominating/corporate governance and compensation committees do have written charters. 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.

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

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

Risks Related to Our Common Stock

The market price and trading volume of our common stock may be volatile.

The market price of our common stock could fluctuate significantly for many reasons, including reasons not specifically related to our performance, such as industry or market trends, reports by industry analysts, investor perceptions, actions by credit rating agencies or negative announcements by our customers or competitors regarding their own performance, as well as general economic and industry conditions. For example, to the extent that other companies within our industry experience declines in their stock price, our stock price may decline as well. Our common stock price is also affected by announcements we make about our business analyst reports related to our company, changes in financial estimates by analysts, rating agency announcements about our business, and future sales of our common stock, among other factors. As a result of these factors, investors in our common stock may not be able to resell their shares at or above the price at which they purchase our common stock. In addition, the stock market in general has experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of companies like us. These broad market and industry factors may materially reduce the market price of our common stock, regardless of our operating performance.

The Goldman Sachs Funds and the Kelso Funds 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, each of the Goldman Sachs Funds and the Kelso Funds controls 36.5% of our outstanding common stock (together, they control 73% 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. CRLLC is party to the Cash Flow Swap with

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J. Aron, an affiliate of the Goldman Sachs Funds, for the period from July 1, 2005 to June 30, 2010. In addition, Goldman Sachs Credit Partners, L.P. is the joint lead arranger for our credit facility. Further, the Goldman Sachs Funds and the Kelso Funds are in the business of making investments in companies and may, from time to time, acquire and hold interests in businesses that compete directly or indirectly with us and they may either directly, or through affiliates, also maintain business relationships with companies that may directly compete with us. In general, the Goldman Sachs Funds and the Kelso Funds or their affiliates could pursue business interests or exercise their voting power as stockholders in ways that are detrimental to us, but beneficial to themselves or to other companies in which they invest or with whom they have a material relationship. Conflicts of interest could also arise with respect to business opportunities that could be advantageous to the Goldman Sachs Funds and the Kelso Funds and they may pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us. Under the terms of our certificate of incorporation, the Goldman Sachs Funds and the Kelso Funds have no obligation to offer us corporate opportunities.

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

Under the terms of the Partnership 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 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 CRLLC Phantom Unit Appreciation Plan (Plan I), or the Phantom Unit Plan I, and phantom points that we granted under the 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 86,243,745 shares of common stock were outstanding as of March 6, 2009. 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. CALLC and CALLC II currently own 31,433,360 shares each which are currently eligible for resale, subject to the limitations of Rule 144. Of these shares, CALLC and CALLC II have made eligible for resale on a shelf registration statement 7,376,265 shares and 7,376,264 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 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.

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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 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.

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

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

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.

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.

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

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

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

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

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

However, there is a risk that we could be deemed an investment company if the SEC or a court determines that our general partner interests in the Partnership are securities or investment securities under the 1940 Act and if our

Partnership interests constituted more than 40% of the value of our total assets. Currently, our interests in the Partnership constitute less than 40% of our total assets on an unconsolidated basis, but they could constitute a higher percentage of the fair market value of our total assets in the future if the value of our Partnership interests increases, the value of our other assets decreases, or some combination thereof occurs.

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

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

The following table contains certain information regarding our principal properties:

Location	Acres	Own/Lease	Use
Coffeyville, KS	440	Own	CVR Energy: oil refinery and office buildings Partnership: fertilizer plant
Phillipsburg, KS	200	Own	Terminal facility
Montgomery County, KS (Coffeyville Station)	20	Own	Crude oil storage
Montgomery County, KS (Broome Station)	20	Own	Crude oil storage
Bartlesville, OK	25	Own	Truck storage and office buildings
Winfield, KS	5	Own	Truck storage
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. We paid rent of approximately $682,000 and $265,000, respectively, in connection with these leases in 2008.

As of December 31, 2008, 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 which is estimated to represent approximately 6% of crude oil storage capacity in the Cushing, Oklahoma hub. 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 are not party to any pending legal proceedings that we believe will have a material impact on our business, and there are no existing legal proceedings where we believe that the reasonably possible loss or range of loss is material.

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

No matter was submitted to a vote of security holders during the fourth quarter of 2008.

PART II

Item 5. ***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:

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

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

Holders of Record

As of March 6, 2009, there were 438 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 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, 2008, 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, 2008 was $4.00. 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, 2008
among CVR Energy, Inc., S&P 500 and a peer group

This performance graph shall not be deemed filed for purposes of Section 18 of the 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.

Equity Compensation Plans

The table below contains information about securities authorized for issuance under our long term incentive plan as of December 31, 2008. This plan was approved by our stockholders in October 2007.

Plan	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
CVR Energy, Inc. Long Term Incentive Plan	32,350	$ 19.08	7,286,530

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 award and performance awards. As of December 31, 2008, 181,120 shares of non-vested common stock have been issued under this plan, of which 78,666 remain unvested.

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Item 6. *Selected Financial Data*

You should read the selected historical consolidated financial data presented below in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the related notes included elsewhere in this Report.

The selected consolidated financial information presented below under the caption Statements of Operations Data for the years ended December 31, 2008, 2007, and 2006 and the selected consolidated financial information presented below under the caption Balance Sheet Data as of December 31, 2008 and 2007 has been derived from our audited consolidated financial statements included elsewhere in this Report, which financial statements have been audited by KPMG LLP, independent registered public accounting firm. The consolidated financial information presented below under the caption Statement of Operations Data for the 233-day period ended December 31, 2005, the 174-day period ended June 23, 2005, the 304-day period ended December 31, 2004, and for the 62-days ended March 2, 2004, and the consolidated financial information presented below under the caption Balance Sheet Data at December 31, 2006, 2005 and 2004, are derived from our audited consolidated financial statements that are not included in this Report.

Prior to March 3, 2004, our assets consisted of one facility within the eight-plant Nitrogen Fertilizer Manufacturing and Marketing Division of Farmland. We refer to our operations as part of Farmland during this period as Original Predecessor. Farmland filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 31, 2002. During periods when we were operated as part of Farmland, which include the 62-days ended March 2, 2004, Farmland allocated certain general corporate expenses and interest expense to Original Predecessor. The allocation of these costs is not necessarily indicative of the costs that would have been incurred if Original Predecessor had operated as a stand-alone entity. Further, the historical results are not necessarily indicative of the results to be expected in future periods.

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

On March 3, 2004, CRLLC completed the purchase of Original Predecessor from Farmland in a sales process under Chapter 11 of the U.S. Bankruptcy Code. We refer to this acquisition as the Initial Acquisition, and we refer to our post-Farmland operations run by Coffeyville Group Holdings, LLC as Immediate Predecessor. Our business was operated by the Immediate Predecessor for the 304-days ended December 31, 2004 and the 174-days ended June 23, 2005. As a result of certain adjustments made in connection with the Initial Acquisition, a new basis of accounting was established on the date of the Initial Acquisition and the results of operations for the 304 days ended December 31, 2004 are not comparable to prior periods.

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

We calculate earnings per share in 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 Immediate Predecessor because we operated under a different capital structure than what we currently operate under and, therefore, the information is not meaningful.

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

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

	Successor				Immediate Predecessor		Original Predecessor
	2008	Year Ended December 31, 2007	2006	233 Days Ended December 31, 2005	174 Days Ended June 23, 2005	304 Days Ended December 31, 2004	62 Days Ended March 2, 2004
	(In millions, except per share data)						
Statements of Operations Data:							
Net sales	$ 5,016.1	$ 2,966.9	$ 3,037.6	$ 1,454.3	$ 980.7	$ 1,479.9	$ 261.1
Cost of product sold(1)	4,461.8	2,308.8	2,443.4	1,168.1	768.0	1,244.2	221.4
Direct operating expenses(1)	237.5	276.1	199.0	85.3	80.9	117.0	23.4
Selling, general and administrative expenses(1)	35.2	93.1	62.6	18.4	18.4	16.3	4.7
Net costs associated with flood(2)	7.9	41.5					
Depreciation and amortization	82.2	60.8	51.0	24.0	1.1	2.4	0.4
Goodwill impairment(3)	42.8						
Operating income	$ 148.7	$ 186.6	$ 281.6	$ 158.5	$ 112.3	$ 100.0	$ 11.2
Other income (expense), net(4)	(5.9)	0.2	(20.8)	0.4	(8.4)	(6.9)	
Interest (expense)	(40.3)	(61.1)	(43.9)	(25.0)	(7.8)	(10.1)	
Gain (loss) on derivatives, net	125.3	(282.0)	94.5	(316.1)	(7.6)	0.5	

Income (loss) before income taxes and minority interest in subsidiaries	$ 227.8	$ (156.3)	$ 311.4	$ (182.2)	$ 88.5	$ 83.5	$ 11.2
Income tax (expense) benefit	(63.9)	88.5	(119.8)	63.0	(36.1)	(33.8)	
Minority interest in (income) loss of subsidiaries		0.2					
Net income (loss)(5)	$ 163.9	$ (67.6)	$ 191.6	$ (119.2)	$ 52.4	$ 49.7	$ 11.2
Earnings per share(6)							
Basic	$ 1.90	$ (0.78)	$ 2.22				
Diluted	$ 1.90	$ (0.78)	$ 2.22				
Weighted average shares(6)							
Basic	86,145,543	86,141,291	86,141,291				
Diluted	86,224,209	86,141,291	86,158,791				
Historical dividends:							
Per preferred unit(7)					$ 0.70	$ 1.50	
Per common unit(7)					$ 0.70	$ 0.48	
Management common units subject to redemption			$ 3.1				
Common units			$ 246.9				

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	Successor				Immediate Predecessor		Original Predecessor
		Year Ended December 31,		233 Days Ended December 31,	174 Days Ended June 23,	304 Days Ended December 31,	62 Days Ended March 2,
	2008	2007	2006	2005	2005	2004	2004
	(In millions, except per share data)						
Balance Sheet Data:							
Cash and cash equivalents	$ 8.9	$ 30.5	$ 41.9	$ 64.7		$ 52.7	
Working capital	128.5	10.7	112.3	108.0		106.6	
Total assets	1,610.5	1,868.4	1,449.5	1,221.5		229.2	
Total debt, including current portion	495.9	500.8	775.0	499.4		148.9	
Minority interest in subsidiaries(8)	10.6	10.6	4.3				
Management units subject to redemption			7.0	3.7			
Divisional/members /stockholders equity	579.5	432.7	76.4	115.8		14.1	
Cash Flow Data:							
Net cash flow provided by (used in):							
Operating activities	83.2	145.9	186.6	82.5	12.7	89.8	53.2
Investing activities	(86.5)	(268.6)	(240.2)	(730.3)	(12.3)	(130.8)	
Financing activities	(18.3)	111.3	30.8	712.5	(52.4)	93.6	(53.2)
Other Financial Data:							
Capital expenditures for property, plant and equipment	86.5	268.6	240.2	45.2	12.3	14.2	
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(9)	11.2	(5.6)	115.4	23.6	52.4	49.7	11.2

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

(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, 2008, December 31, 2007 and December 31, 2006, the 174-days ended June 23, 2005, and the 304-days ended December 31, 2004, we recognized a loss of $10.0 million, $1.3 million, $23.4 million, $8.1 million and $7.2 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:

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	Successor				Immediate Predecessor		Original Predecessor
	Year Ended December 31,			233 Days Ended December 31,	174 Days Ended June 23,	304 Days Ended December 31,	62 Days Ended March 2,
	2008	2007	2006	2005	2005	2004	2004
Loss on extinguishment of debt(a)	$ 10.0	$ 1.3	$ 23.4	$	$ 8.1	$ 7.2	$
Inventory fair market value adjustment(b)				16.6		3.0	
Funded letter of credit expense and interest rate swap not included in interest expense(c)	7.4	1.8		2.3			
Major scheduled turnaround expense(d)	3.3	76.4	6.6			1.8	
Loss on termination of swap(e)				25.0			
Unrealized (gain) loss from Cash Flow Swap	(253.2)	103.2	(126.8)	235.9			
Share-based compensation(f)	(42.5)	44.1	16.9	1.1	4.0	0.1	
Goodwill impairment(g)	42.8						

(a) Represents the write-off of $10.0 million of deferred financing costs in connection with the second amendment to our credit facility on December 22, 2008, the write-off of $1.3 million of deferred financing costs in connection with the repayment and termination of three credit facilities on October 26, 2007, the write-off of $23.4 million in connection with the refinancing of our senior secured credit facility on December 28, 2006, the write-off of $8.1 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on June 23, 2005 and the write-off of $7.2 million of deferred financing costs in connection with the refinancing of our senior secured credit facility on May 10, 2004.

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

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

(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 and the 304-day period ended December 31, 2004 are calculated based on the ownership structure of Immediate Predecessor.

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

(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 Subsequent Acquisition. On June 16, 2005, CALLC 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 CALLC to CRLLC on June 24, 2005. The derivative 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 fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 57% and 14% of crude oil capacity for the periods January 1, 2009 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to terminate the Cash Flow Swap in 2009 or 2010.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current U.S. generally accepted accounting principles, consistently applied (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 increase, we are 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 decline, we are 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 or liquidity in evaluating our business. Because Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap excludes mark to market adjustments, the measure does not reflect the fair market value of our Cash Flow Swap in our net income. As a result, the measure does not include potential cash payments that may be required to be made on the Cash Flow Swap in the future. Also, our presentation of this non-GAAP measure may not be comparable to similarly titled measures of other companies.

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

	Successor				Immediate Predecessor		Original Predecessor
	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006	233 Days Ended December 31, 2005	174 Days Ended June 23, 2005	304 Days Ended December 31, 2004	62 Days Ended March 2, 2004
Net income (loss) adjusted for unrealized gain (loss) from Cash Flow Swap	$ 11.2	$ (5.6)	$ 115.4	$ 23.6	$ 52.4	$ 49.7	$ 11.2
Plus:							
Unrealized gain (loss) from Cash Flow Swap, net of tax effect	152.7	(62.0)	76.2	(142.8)			
Net income (loss)	$ 163.9	$ (67.6)	$ 191.6	$ (119.2)	$ 52.4	$ 49.7	$ 11.2

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with our financial statements and related notes included elsewhere in this Report.

Forward-Looking Statements

This 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 Risk Factors and contained elsewhere in this Report.

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

Overview and Executive Summary

We are an independent refiner and marketer of high value transportation fuels. In addition, we currently own all of the interests (other than the managing general partner interest and associated IDRs) in a limited partnership which produces the nitrogen fertilizers ammonia and UAN.

We operate under two business segments: petroleum and nitrogen fertilizer. For the fiscal years ended December 31, 2008, 2007 and 2006, we generated combined net sales of $5.0 billion, $3.0 billion and $3.0 billion, respectively. Our petroleum business generated $4.8 billion, $2.8 billion and $2.9 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 21%, 78% and 87% 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 refinery in Coffeyville, Kansas. In addition, supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma, western Missouri, eastern Colorado and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, (3) a 145,000 bpd pipeline system that transports crude oil to our refinery and associated crude oil storage tanks with a capacity of 1.2 million barrels and (4) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and at throughput terminals on Magellan s refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise and NuStar. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States. Cushing is supplied by numerous pipelines from locations including the U.S. Gulf Coast and Canada, providing us with access to virtually any crude variety in the world capable of being transported by pipeline.

Crude is supplied to our refinery through our owned and leased gathering system and by a Plains pipeline from Cushing, Oklahoma. We maintain capacity on the Spearhead Pipeline from Canada and receive foreign and deepwater domestic crudes via the Seaway Pipeline system. We have also signed a contract for additional pipeline capacity on the proposed Keystone pipeline project currently under development. We also maintain leased storage in Cushing to facilitate optimal crude purchasing and blending. Our refinery blend consists of a combination of crude grades, including onshore and offshore domestic grades, various Canadian medium and heavy sours and sweet synthetics and a variety of South American, North Sea, Middle East and West African imported grades. The access to a variety of crudes 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 2008 was $2.12 per barrel compared to $5.04 per barrel in 2007 and $4.57 per barrel in 2006.

Nitrogen fertilizer business. The nitrogen fertilizer segment 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) an 84 million standard cubic foot per day gasifier complex, which consumes approximately 1,500 tons per day of pet coke to produce hydrogen. In 2008, the nitrogen fertilizer business produced approximately 359,120 tons of ammonia, of which approximately 69% was upgraded into approximately 599,172 tons of UAN. The nitrogen fertilizer business generated net sales of $263.0 million, $165.9 million and $162.5 million, and operating income of $116.8 million, $46.6 million and $36.8 million, for the years ended December 31, 2008, 2007 and 2006, respectively.

The nitrogen fertilizer plant in Coffeyville, Kansas includes a pet coke gasifier that produces high purity hydrogen which in turn is converted to ammonia at a related ammonia synthesis plant. Ammonia is further upgraded into UAN solution in a related UAN unit. Pet coke is a low value by-product of the refinery coking process. On average during the last five years, more than 77% of the pet coke consumed by the nitrogen fertilizer plant was produced by our refinery. The nitrogen fertilizer business obtains most of its pet coke via a long-term coke supply agreement with us. As such, the nitrogen fertilizer business benefits from high natural gas prices, as fertilizer prices generally increase with natural gas prices, without a directly related change in cost (because pet coke is used as a primary raw material rather than natural gas).

The nitrogen fertilizer plant is the only commercial facility in North America utilizing a pet coke gasification process to produce nitrogen fertilizers. Its redundant train gasifier provides good on-stream

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reliability and the use of low cost by-product pet coke feed (rather than natural gas) to produce hydrogen provides the facility with a significant competitive advantage due to currently high and volatile natural gas prices. The nitrogen fertilizer business competition utilizes natural gas to produce ammonia. Historically, pet coke has been a less expensive feedstock than natural gas on a per-ton of fertilizer produced basis.

CVR Energy s Initial Public Offering

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

The net proceeds from the offering were used to repay $280.0 million of our outstanding term loan debt and to repay in full the $25.0 million secured credit facility and the $25.0 million unsecured credit facility. We also repaid $50.0 million of indebtedness under our revolving credit facility. Associated with the repayment of the $25.0 million secured facility and the $25.0 million unsecured facility, we recorded a write-off of unamortized deferred financing fees of approximately $1.3 million in the fourth quarter of 2007.

In connection with the initial public offering, we also became the indirect owner of CRLLC and all of its refinery assets and its interest in the nitrogen fertilizer business. This was accomplished by the issuance of 62,866,720 shares of our common stock to certain entities controlled by our majority stockholder pursuant to a stock split in exchange for the interests in certain subsidiaries of CALLC and CALLC II. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, excluding any non-vested shares issued.

CVR s Shelf Registration Statement

On March 6, 2009, the SEC declared effective our registration statement on Form S-3, which will enable (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.

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 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 2-1-1 crack spread. The 2-1-1 crack spread is expressed in dollars per barrel and is a proxy for the per barrel margin that a sweet crude refinery would earn assuming it produced and sold the benchmark production of gasoline and distillate.

Although the 2-1-1 crack spread is a benchmark for our refinery margin, because our refinery has certain feedstock costs and 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 and heavy sour crude we purchase as a percent of our total crude volume and will correlate more closely with such published differentials the heavier and more sour the crude oil slate. The WTI less WCS differential was $18.72 and $22.94 per barrel, for the years ended December 31, 2008 and 2007, respectively. The WTI less WTS differential was $3.44, $5.16 and $5.36 per barrel for the years ended December 31, 2008, 2007 and 2006, respectively. The Company s consumed crude differential was $2.12, $5.04 and $4.57 per barrel for the years ended December 31, 2008, 2007 and 2006, 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 heating oil PADD II, Group 3 vs. NYMEX basis, or heating oil basis. Both gasoline and heating oil basis are greater than zero, which means that prices in our marketing area exceed those used in the 2-1-1 crack spread. Since 2003, the market indicator for the heating oil basis has been positive in all periods presented, including a decrease to $4.22 per barrel for 2008 from $7.95 per barrel in 2007 and $7.42 per barrel for 2006. Gasoline basis for 2008 was $0.12 per barrel, compared to $3.56 per barrel in 2007 and $1.52 per barrel for 2006. 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. The last petroleum refinery turnaround was completed in April 2007, and the next petroleum refinery turnaround is scheduled for the fourth quarter of 2011.

Because petroleum feedstocks and products are essentially commodities, we have no control over the changing market. Therefore, the lower target inventory we are able to maintain significantly reduces the impact of commodity price volatility on our petroleum product inventory position relative to other refiners. This target inventory position is generally not hedged. To the extent our inventory position deviates from the target level, we consider risk mitigation activities usually through the purchase or sale of futures contracts on the NYMEX. Our hedging activities carry customary time, location and product grade basis risks generally associated with hedging activities. Because most of our titled inventory is valued under the FIFO costing method, price fluctuations on our target level of titled inventory have a major effect on our financial results unless the market value of our target inventory is increased above cost.

Nitrogen Fertilizer Business

In the nitrogen fertilizer business, earnings and cash flow from operations are primarily affected by the relationship between nitrogen fertilizer product prices and direct operating expenses. Unlike its competitors, the nitrogen fertilizer business uses minimal natural gas as feedstock and, as a result, is not directly impacted in terms of cost, by high or volatile swings in natural gas prices. Instead, our adjacent oil refinery supplies most of the pet coke feedstock needed by the nitrogen fertilizer business pursuant to a long-term coke supply agreement we entered into in October 2007. The price at which nitrogen fertilizer products are ultimately sold depends on numerous factors, including the supply of, and the demand for, nitrogen fertilizer products which, in turn, depends on, among other factors, the price of natural gas, the cost and availability of fertilizer transportation infrastructure, changes in the world population, weather conditions, grain production levels, the availability of imports, and the extent of government intervention in agriculture markets. While net sales of the nitrogen fertilizer business could fluctuate significantly with movements in natural gas prices during periods when fertilizer markets are weak and nitrogen fertilizer products sell at low prices, high natural gas prices do not force the nitrogen fertilizer business to shut down its operations as is the case with our competitors who rely heavily on natural gas instead of pet coke as a primary feedstock.

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

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

Natural gas is the most significant raw material required in the production of most nitrogen fertilizers. North American natural gas prices have increased substantially and, since 1999, have become significantly more volatile. In

2005, North American natural gas prices reached unprecedented levels due to the impact

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hurricanes Katrina and Rita had on an already tight natural gas market. Recently, natural gas prices have moderated, returning to pre-hurricane levels or lower.

In order to assess the operating performance of the nitrogen fertilizer business, we calculate plant gate price to determine our operating margin. Plant gate price refers to the unit price of fertilizer, in dollars per ton, offered on a delivered basis, excluding shipment costs. Instead of experiencing high variability in the cost of raw materials, the nitrogen fertilizer business utilizes less than 1% of the natural gas relative to other natural gas-based fertilizer producers.

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 targeted end users in the U.S. farm belt where it incurs lower freight costs as compared to 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 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 2008, the nitrogen fertilizer business upgraded approximately 69% 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, employee labor, maintenance, including contract labor, and outside services. These costs comprise the fixed costs associated with the nitrogen fertilizer plant. Variable costs associated with the nitrogen fertilizer plant have averaged approximately 1.5% of direct operating expenses over the 24 months ended December 31, 2008. The average annual operating costs over the 24 months ended December 31, 2008 have approximated $76 million, of which substantially all are fixed in nature.

The nitrogen fertilizer business largest raw material expense is pet coke, which it purchases from us and third parties. In 2008, the nitrogen fertilizer business spent $14.1 million for pet coke. If pet coke prices rise substantially in the future, the nitrogen fertilizer business may be unable to increase its prices to recover increased raw material costs, because market prices for nitrogen fertilizer products are generally correlated with natural gas prices, the primary raw material used by its competitors, and not pet coke prices.

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

The nitrogen fertilizer business generally undergoes a facility turnaround every two years. The turnaround typically lasts 15-20 days each turnaround year and costs approximately $3-5 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 coke supply agreement mentioned above, under which we sell pet coke to the nitrogen fertilizer business; a services agreement, in which our management operates the nitrogen fertilizer business; a feedstock and shared services agreement, which governs the provision of feedstocks, including hydrogen, high-pressure steam, nitrogen, instrument air, oxygen and natural gas; a raw water and facilities sharing agreement, which allocates raw water resources between the two businesses; an easement agreement; an environmental agreement; and a lease agreement pursuant to which we lease office space and laboratory space to the Partnership.

The price paid by the nitrogen fertilizer business pursuant to the coke supply agreement is based on the lesser of a coke price derived from the price received by the Partnership for UAN (subject to a UAN based price ceiling and floor) and a coke price index for pet coke. For the periods prior to our entering into the 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 coke price of $15 per ton beginning in March 2004. This is reflected in the segment data in our historical financial statements as a cost for the nitrogen fertilizer business and as revenue for the petroleum business. If the terms of the coke supply agreement had been in place in 2007 and 2006, the new coke supply agreement would have resulted in an increase (or decrease) in cost of product sold (exclusive of depreciation and amortization) for the nitrogen fertilizer business (and an increase (or decrease) in revenue for the petroleum business) of $2.5 million, and ($3.5) million for the years ended December 31, 2007 and 2006, respectively. There would have been no impact to the consolidated financial statements as intercompany transactions are eliminated upon consolidation.

In addition, due to the services agreement between the parties, historical nitrogen fertilizer segment operating income would have increased $8.9 million and $7.4 million for the years ended December 31, 2007 and 2006, respectively, assuming an annualized $11.5 million charge for the management services in lieu of the historical allocations of selling, general and administrative expenses. The petroleum segment s operating income would have had offsetting decreases for these periods.

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

Factors Affecting Comparability

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

2007 Flood and Crude Oil Discharge

During the weekend of June 30, 2007, torrential rains in southeastern Kansas caused the Verdigris River to overflow its banks and flood the city of Coffeyville. Our refinery and the nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were flooded, sustained major damage and required repairs. In addition, despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007.

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, 2008 and December 31, 2007 include net pretax costs of $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 year ended December 31, 2008. We reported reduced revenue due to the closure of our facilities for a portion of the third quarter of 2007, as well as significant costs related to the flood as a result of the necessary repairs to our facilities and environmental remediation.

Refinancing and Prior Indebtedness

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. Of these costs, we immediately expensed $4.7 million, 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 August 2007, our subsidiaries entered into a $25.0 million secured facility, a $25.0 million unsecured facility and a $75.0 million unsecured facility. No amounts were drawn under the $75.0 million unsecured facility. Our Statement of Operations for the year ended December 31, 2007 includes $0.9 million in interest expense related to these facilities with no comparable amount for the same period in 2008.

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.

On December 28, 2006, CRLLC entered into a new credit facility and used the proceeds thereof to repay its then existing first lien credit facility and second lien credit facility, and to pay a dividend to the members of CALLC. As a result, interest expense for the year ended December 31, 2007 was significantly higher than interest expense for the year ended December 31, 2006. Consolidated interest expense for the years ended December 31, 2008, 2007, and 2006 was $40.3 million, $61.1 million, and $43.9 million, respectively.

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) which we owed to J. Aron as of December 31, 2007. 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 agreed to release 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 fourth quarter review of goodwill, we recorded non-cash charges of $42.8 million during the fourth quarter of 2008, 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.

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

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

Public Company Expenses

Our financial statements following the initial public offering reflect the impact of increased general and administrative expenses associated with the additional costs of operating as a public company. Increased costs related to legal, accounting, compliance, start up costs associated with complying with the provisions of Section 404 of the Sarbanes-Oxley Act, increased insurance premiums and investor relations impact the results of our Statements of Operations for periods after our initial public offering, whereas our financial statements for periods prior to the initial public offering do not reflect these additional expenses.

2008 and 2007 Turnarounds

In October 2008, we completed a planned turnaround of our nitrogen fertilizer plant at a total cost of approximately $3.3 million. The majority of these costs were expensed in the fourth quarter of 2008. 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.

Cash Flow Swap

On June 16, 2005, CALLC entered into the Cash Flow Swap with J. Aron. The Cash Flow Swap was subsequently assigned from CALLC to CRLLC on June 24, 2005. The derivative 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 fall below the fixed level, J. Aron agreed to pay the difference to us, and if absolute crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 57% and 14% of crude oil capacity for the periods January 1, 2009 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility, having met specific requirements related to our leverage ratio and our credit ratings, we are allowed to terminate the Cash Flow Swap in 2009 or 2010, at which time any unrealized loss would become a fixed obligation. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. As a result, the Statement of Operations reflects all the realized and unrealized gains and losses from this swap which can create significant changes between periods.

For the year ended December 31, 2008, we recorded net realized losses of $110.4 million and net unrealized gains of $253.2 million. For the year ended December 31, 2007, we recorded net realized losses of $157.2 million and net unrealized losses of $103.2 million. For the year ended December 31, 2006, we recorded net realized losses of $46.8 million and net unrealized gains of $126.8 million.

Share-Based Compensation

The Company accounts for awards under its Phantom Unit Plans as liability based awards. In accordance with FAS 123(R), the expense associated with these awards for 2008 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.

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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 the accounting guidance in EITF 00-12 and EITF 96-18. In accordance with that accounting guidance, the expense associated with the awards is based on the current fair value of the awards which is derived in 2008 under the same methodology as the Phantom Unit Plan, as remeasured at each reporting date until the awards vest. Prior to October 2007, the expense associated with the override units was based on the original grant date fair value of the awards. For the year ending December 31, 2008, we reduced compensation expense by $43.3 million as a result of the phantom and override unit share-based compensation awards. For the years ending December 31, 2007 and December 31, 2006, we increased compensation expense by $43.5 million and $12.6 million, respectively, as a result of the phantom and override unit share-based compensation awards.

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, 2008, we own all of the interests in the Partnership (other than the managing general partner interest and associated IDRs) and are entitled to all cash that is distributed by the Partnership, 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 the managing general partner and have joint management rights regarding specified major business decisions relating to the Partnership.

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

Using criteria in FIN 46R, management has determined that we are the primary beneficiary of the Partnership, although 100% of the managing general partner interest is owned by 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 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. While it is impossible to predict refining margins due to the uncertainties associated with global crude oil supply and global and domestic demand for refined products, we believe that refining margins for U.S. refineries will generally remain above those experienced in the periods prior to 2003. Our marketing region continues to be undersupplied and is a net importer of transportation fuels.

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

As of the beginning of March 2009, NYMEX crude oil futures have been in contango. 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. We believe that our 2.7 million barrels of crude oil storage in Cushing, Oklahoma allows us to take advantage of the contango market. Our refining economics in January and February 2009 have benefited from relatively lower priced WTI crude coupled with strong cash refining margins. Our Group 3 product basis differentials have been seasonally negative, but in aggregate the contango crude market has more than offset this condition. We expect the contango market to adjust to more normal conditions.

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.

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Over the last two years the nitrogen fertilizer market was driven by an unprecedented increase in demand. According to the United States Department of Agriculture (USDA), U.S. farmers planted 93.6 million acres of corn in 2007 and 85.9 million acres in 2008. The global economic downturn has impacted the nitrogen fertilizer market, largely through uncertainty about both production and demand for ethanol. The USDA is projecting 86.0 million acres of corn will be planted in 2009. We expect that this level of production will translate to increased 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 applications of 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, the floor price of which is directly influenced by natural gas prices. Natural gas prices have been and continue to be volatile.

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. As of March 2009, ammonia and UAN prices are down from the comparable time period in 2008, but are in line with those in early 2007. As of March 2009, the company s order book for UAN has slightly over 90,000 tons at an average price of just over $380 per ton.

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, 2008 with the year ended December 31, 2007 and the year ended December 31, 2007 with the year ended December 31, 2006.

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.

We changed our corporate selling, general and administrative allocation method to the operating segments in 2007. The effect of the change on operating income for the year ended December 31, 2006 would have been a decrease of $6.0 million, to the petroleum segment and an increase of $6.0 million to the nitrogen fertilizer segment.

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

Consolidated Financial Results	Year Ended December 31, 2008	2007	2006
		(in millions)	
Net sales	$ 5,016.1	$ 2,966.9	$ 3,037.6
Cost of product sold (exclusive of depreciation and amortization)	4,461.8	2,308.8	2,443.4
Direct operating expenses (exclusive of depreciation and amortization)	237.5	276.1	199.0
Selling, general and administrative expense (exclusive of depreciation and amortization)	35.2	93.1	62.6
Net costs associated with flood(1)	7.9	41.5	
Depreciation and amortization(2)	82.2	60.8	51.0
Goodwill impairment(3)	42.8		
Operating income	$ 148.7	$ 186.6	$ 281.6
Net income (loss)(4)	163.9	(67.6)	191.6
Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap(5)	11.2	(5.6)	115.4

(1) Represents the costs associated with the June/July 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, 2008	2007	2006
		(in millions)	
Depreciation and amortization excluded from cost of product sold	$ 2.5	$ 2.4	$ 2.2
Depreciation and amortization excluded from direct operating expenses	78.0	57.4	47.7
Depreciation and amortization excluded from selling, general and administrative expense	1.7	1.0	1.1
Depreciation included in net costs associated with flood		7.6	
Total depreciation and amortization	$ 82.2	$ 68.4	$ 51.0

(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 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,** **2008**	**2007** (in millions)	**2006**
Loss of extinguishment of debt(a)	$ 10.0	$ 1.3	$ 23.4
Funded letter of credit expense & interest rate swap not included in interest expense(b)	7.4	1.8	
Major scheduled turnaround expense(c)	3.3	76.4	6.6
Unrealized (gain) loss from Cash Flow Swap	(253.2)	103.2	(126.8)
Share-based compensation expense(d)	(42.5)	44.1	16.9
Goodwill impairment(e)	42.8		

(a) 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. The write-off of $1.3 million in connection with the repayment and termination of three credit facilities on October 26, 2007 and the $23.4 million was written off in connection with the refinancing of our senior secured credit facility on December 28, 2006.

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

(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 Subsequent Acquisition. On June 16, 2005, CALLC entered into the Cash Flow Swap with J. Aron, a subsidiary of The Goldman Sachs Group, Inc., and a related party of ours. The Cash Flow Swap was subsequently assigned from CALLC to CRLLC on June 24, 2005. The derivative took the form of three NYMEX swap agreements whereby if crack spreads fall below the fixed level, J. Aron agreed to pay the difference to us, and if crack spreads rise above the fixed level, we agreed to pay the difference to J. Aron. The Cash Flow Swap represents approximately 57% and 14% of crude oil capacity for the periods January 1, 2009 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our credit facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we are permitted to terminate the Cash Flow Swap in 2009 or 2010.

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, 2008**	**2007 (in millions)**	**2006**
Net Income (loss) adjusted for unrealized gain or loss from Cash Flow Swap	$ 11.2	$ (5.6)	$ 115.4
Plus:			
Unrealized gain or (loss) from Cash Flow Swap, net of taxes	152.7	(62.0)	76.2
Net income (loss)	$ 163.9	$ (67.6)	$ 191.6

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.

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 segment 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 segment 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 segment 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.

Interest Income. Interest income was $2.7 million for the year ended December 31, 2008 as compared to $1.1 million for the year ended December 31, 2007.

Gain (Loss) on Derivatives, Net. We have determined that the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* For the 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, 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 minority interest in subsidiaries, as compared to an income tax benefit of $88.5 million, or 56.6% of loss before income taxes and minority interest in subsidiaries, 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 High Performance Incentive Program (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.

Minority Interest in (income) loss of Subsidiaries. Minority interest in loss of subsidiaries for the year ended December 31, 2008 was zero compared to $0.2 million for the year ended December 31, 2007. Minority interest relates to common stock in two of our subsidiaries owned by our chief executive officer. In October 2007, in connection with our initial public offering, our chief executive officer exchanged his common stock in our subsidiaries for common stock of CVR Energy.

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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.

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

Net Sales. Consolidated net sales were $2,966.9 million for the year ended December 31, 2007 compared to $3,037.6 million for the year ended December 31, 2006. The decrease of $70.7 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily due to a decrease in petroleum net sales of $74.2 million that resulted from lower sales volumes ($576.9 million), partially offset by higher product prices ($502.7 million). Nitrogen fertilizer net sales increased $3.4 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 as reductions in overall sales volumes ($31.0 million) were more than offset by higher plant gate prices ($34.4 million). The sales volume decrease for the refinery primarily resulted from a significant reduction in refined fuel production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007, and the refinery downtime resulting from the June/July 2007 flood. The June/July 2007 flood was also a major contributor to lower nitrogen fertilizer sales volume.

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

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

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

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

Depreciation and Amortization. Consolidated depreciation and amortization was $60.8 million for the year ended December 31, 2007 as compared to $51.0 million for the year ended December 31, 2006. During the restoration period for the refinery and our nitrogen fertilizer operations due to the June/July 2007 flood, $7.6 million of depreciation and amortization was reclassified into net costs associated with flood. Adjusting for this $7.6 million reclassification, the increase in consolidated depreciation and amortization for the year ended December 31, 2007 compared to the year ended December 31, 2006 would have been approximately $17.4 million. This adjusted increase in consolidated depreciation and amortization for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of the completion of several large capital projects in late 2006 and during the year ended December 31, 2007 in our Petroleum business

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

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

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

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

Provision for Income Taxes. Income tax benefit for the year ended December 31, 2007 was $88.5 million, or 56.6% of loss before income taxes, as compared to income tax expense of $119.8 million, or 38.5% of earnings before income taxes, for the year ended December 31, 2006. Our effective tax rate increased in the year ended December 31, 2007 as compared to the year ended December 31, 2006 primarily due to the impact of the American Jobs Creation Act of 2004, which provides an income tax credit to small business refiners related to the production of ultra low sulfur diesel. We recognized a federal income tax benefit of approximately $17.3 million in 2007 compared to $4.5 million in 2006 on a credit of approximately $26.6 million in 2007 compared to a credit of approximately $6.9 million in 2006 related to the production of ultra low sulfur diesel. In addition, state income tax credits, net of federal expense, approximating $19.8 million were earned and recorded in 2007 that related to the expansion of the facilities in Kansas.

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

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

Petroleum Business Results of Operations

Refining margin is a measurement calculated as the difference between net sales and cost of 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 comparative measure. The following table shows selected information about our petroleum business including refining margin:

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
<u>Petroleum Business Financial Results</u>			
Net sales	$ 4,774.3	$ 2,806.2	$ 2,880.4
Cost of product sold (exclusive of depreciation and amortization)	4,449.4	2,300.2	2,422.7
Direct operating expenses (exclusive of depreciation and amortization)	151.4	209.5	135.3
Net costs associated with flood	6.4	36.7	
Depreciation and amortization	62.7	43.0	33.0
Gross profit	$ 104.4	$ 216.8	$ 289.4
Plus direct operating expenses (exclusive of depreciation and amortization)	151.4	209.5	135.3
Plus net costs associated with flood	6.4	36.7	

Plus depreciation and amortization		62.7		43.0		33.0
Refining margin(1)	$	324.9	$	506.0	$	457.7
Goodwill impairment(2)	$	42.8	$		$	
Operating income	$	31.9	$	144.9	$	245.6

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	Year Ended December 31, 2008	2007	2006
	(dollars per barrel)		
Key Operating Statistics			
Refining margin per crude oil throughput barrel(1)(3)	$ 8.39	$ 18.17	$ 13.27
Direct operating expenses (exclusive of depreciation and amortization)	3.91	7.52	3.92
Gross profit	2.69	7.79	8.39

	Year Ended December 31, 2008	%	2007	%	2006	%
Refining Throughput and Production Data (Bpd)						
Throughput:						
Sweet	77,315	65.7	54,509	66.4	51,803	50.5
Light/medium sour	16,795	14.3	14,580	17.8	41,907	40.8
Heavy sour	11,727	10.0	7,228	8.8	847	0.8
Total crude oil throughput	105,837	90.0	76,317	93.0	94,557	92.1
All other feed and blendstocks	11,882	10.0	5,748	7.0	8,034	7.9
Total throughput	117,719	100.0	82,065	100.0	102,591	100.0
Production:						
Gasoline	56,852	48.0	37,017	44.9	48,248	46.7
Distillate	48,257	40.7	34,814	42.3	42,175	40.8
Other (excluding internally produced fuel)	13,422	11.3	10,551	12.8	12,896	12.5
Total refining production (excluding internally produced fuel)	118,531	100.0	82,382	100.0	103,319	100.0
Product price (dollars per gallon):						
Gasoline		$ 2.50		$ 2.20		$ 1.88
Distillate		$ 3.00		$ 2.28		$ 1.99
Market Indicators (dollars per barrel)						
West Texas Intermediate (WTI) NYMEX		$ 99.75		$ 72.36		$ 66.25
Crude Oil Differentials:						
WTI less WTS (light/medium sour)		3.44		5.16		5.36
WTI less WCS (heavy sour)		18.72		22.94		N/A
NYMEX Crack Spreads:						
Gasoline		4.76		14.61		10.53
Heating Oil		20.25		13.29		11.14
NYMEX 2-1-1 Crack Spread		12.50		13.95		10.84

PADD II Group 3 Basis:			
Gasoline	0.12	3.56	1.52
Ultra Low Sulfur Diesel	4.22	7.95	7.42
PADD II Group 3 Product Crack:			
Gasoline	4.88	18.18	12.05
Ultra Low Sulfur Diesel	24.47	21.24	18.56
PADD II Group 3 2:1:1	14.68	19.71	15.31

(1) 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 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 Statement of Operations. Our calculation of refining margin may differ from similar calculations of other companies in our industry, thereby limiting its usefulness as a comparative measure. 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.

(2) 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 segment 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 segment operating income but is excluded in the refining margin and the refining margin per crude oil throughput barrel.

(3) In order to derive the refining margin, direct operating expenses and gross profit, in each case 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.

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. 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 per barrel of crude throughput decreased from $18.17 for the year ended December 31, 2007 to $8.39 for the year ended December 31, 2008 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, and the WTS price, which is an indicator for the price of sour crude, 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), 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 throughput basis, direct operating expenses per barrel of crude 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.

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 segment 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 an increase in the cost of product sold driven by record high crude oil prices. In addition, the Petroleum segment recorded a non-cash charge related to the impairment of goodwill of $42.8 million compared to none in 2007. Partially offsetting these negative impacts was a significant decrease in direct operating expenses during the year ended December 31, 2008 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), 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).

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

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

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold includes cost of crude oil, other feedstocks and blendstocks, purchased products for resale, transportation and distribution costs. Petroleum cost of product sold exclusive of depreciation and amortization was $2,300.2 million for the year ended December 31, 2007 compared to $2,422.7 million for the year ended December 31, 2006. The decrease of $122.5 million from the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of a significant reduction in crude throughput due to the refinery turnaround which began in February 2007 and was completed in April 2007 and the refinery downtime resulting from the June/July 2007 flood. In addition to the refinery turnaround and the June/July 2007 flood, crude oil prices, reduced sales volumes and the impact of FIFO accounting also impacted cost of product sold during the comparable periods. Our average cost per barrel of crude oil for the year ended December 31, 2007 was $70.06, compared to $61.71 for the comparable period of 2006, an increase of 14%. Sales volume of refined fuels decreased 18% for the year ended December 31, 2007 as compared to the year ended December 31, 2006 principally due to the refinery turnaround and 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, 2007, we had a favorable FIFO impact of $69.9 million compared to an unfavorable FIFO impact of $7.6 million for the comparable period of 2006.

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

Direct Operating Expenses Exclusive of Depreciation and Amortization. Direct operating expenses for our Petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $209.5 million for the year ended December 31, 2007 compared to direct operating expenses of $135.3 million for the year ended December 31, 2006. The increase of $74.2 million for the year ended December 31, 2007 compared to the year ended December 31, 2006 was the result of increases in expenses associated with repairs and maintenance related to the refinery turnaround ($67.3 million), taxes ($9.3 million), direct labor ($5.0 million), insurance ($2.4 million), production chemicals ($0.8 million) and outside services ($0.7 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with energy and utilities ($5.8 million), rent and lease ($2.4 million), environmental compliance ($1.4 million), operating materials ($0.8 million) and repairs and maintenance ($0.3 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude throughput for the year ended December 31, 2007 increased to $7.52 per barrel as compared to $3.92 per barrel for the year ended December 31, 2006 principally due to refinery turnaround expenses and the related downtime associated with the turnaround and the 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, 2007 approximated $36.7 million as compared to none for the year ended December 31, 2006. Total gross costs recorded for the year ended December 31, 2007 were approximately $138.0 million. Of these gross costs approximately $93.1 million were associated with repair and other matters as a result of the physical damage to the refinery and approximately $44.9 million were associated with the environmental remediation and property damage. Included in the gross costs associated with the June/July 2007 flood were certain costs that are excluded from the accounts receivable from insurers of $81.4 million at December 31, 2007, for which we believe collection is probable. The costs excluded from the accounts receivable from insurers were approximately $6.8 million recorded for depreciation for the temporarily idle facilities, $3.5 million of uninsured losses inside of our deductibles, $2.8 million of uninsured expenses and $23.5 million recorded with respect to environmental remediation and property damage. As of December 31, 2007, $20.0 million of insurance recoveries recorded in 2007 had been collected and are not reflected in the accounts receivable from insurers balance at December 31, 2007.

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

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

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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, 2008	2007 (in millions)	2006
Net sales	$ 263.0	$ 165.9	$ 162.5
Cost of product sold (exclusive of depreciation and amortization)	32.6	13.0	25.9
Direct operating expenses (exclusive of depreciation and amortization)	86.1	66.7	63.7
Net costs associated with flood		2.4	
Depreciation and amortization	18.0	16.8	17.1
Operating income	116.8	46.6	36.8

Key Operating Statistics	Year Ended December 31, 2008	2007	2006
Production (thousand tons):			
Ammonia (gross produced)(1)	359.1	326.7	369.3
Ammonia (net available for sale)(1)	112.5	91.8	111.8
UAN	599.2	576.9	633.1
Petroleum coke consumed (thousand tons)	451.9	449.8	439.0
Petroleum coke (cost per ton)	$ 31	$ 30	$ 19
Sales (thousand tons)(2):			
Ammonia	99.4	92.1	117.3
UAN	594.2	555.4	645.5
Total sales	693.6	647.5	762.8
Product pricing (plant gate) (dollars per ton)(2):			
Ammonia	$ 557	$ 376	$ 338
UAN	$ 303	$ 211	$ 162
On-stream factor(3):			
Gasification	87.8%	90.0%	92.5%
Ammonia	86.2%	87.7%	89.3%
UAN	83.4%	78.7%	88.9%
Reconciliation to net sales (dollars in thousands):			
Freight in revenue	$ 18,856	$ 13,826	$ 17,890
Hydrogen revenue	8,967		
Sales net plant gate	235,127	152,030	144,575
Total net sales	$ 262,950	$ 165,856	$ 162,465

Market Indicators	Year Ended December 31, 2008	2007	2006

Natural gas NYMEX (dollars per MMBtu)	$ 8.91	$ 7.12	$ 6.98
Ammonia Southern Plains (dollars per ton)	$ 707	$ 409	$ 353
UAN Mid Cornbelt (dollars per ton)	$ 422	$ 288	$ 197

(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 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 2008 adjusted for turnaround would have been 91.7% for gasifier, 90.2% for ammonia and 87.4% for UAN, (ii) 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 and (iii) the on-stream factors in 2006 adjusted for turnaround would have been 97.1% for gasifier, 94.3% for ammonia and 93.6% for UAN.

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 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 plant completed in October 2008. It is typical to experience brief outages in complex manufacturing operations such as our nitrogen fertilizer plant which result in less than one hundred percent on-stream availability for one or more specific units. After the 2008 turnaround, the gasifier on-stream rate rose to nearly 100% for the remainder of the year and maximum hydrogen output from our gasifier complex increased approximately 5%.

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 nature gas prices.

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

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold (exclusive of depreciation and amortization) is primarily comprised of 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 our nitrogen plant, such as repairs and maintenance, energy and utility costs, catalyst and chemical costs, outside services, labor and environmental compliance costs. Nitrogen direct operating expenses (exclusive of depreciation and amortization) for the year ended December 31, 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 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 segment 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 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).

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

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

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

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

Plant gate prices are prices 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, 2007 for ammonia and UAN were greater than plant gate prices for the comparable period of 2006 by 11% and 30%, respectively. Our ammonia and UAN sales prices for product shipped during the year ended December 31, 2006 generally followed volatile natural gas prices; however, it is typical for the reported pricing in our fertilizer business to lag the spot market prices for nitrogen fertilizer due to forward price contracts. As a result, forward price contracts entered into the late summer and fall of 2005 (during a period of relatively high natural gas prices due to the impact of hurricanes Rita and Katrina) comprised a significant portion of the product shipped in the spring of 2006. However, as natural gas prices moderated in the spring and summer of 2006, nitrogen fertilizer prices declined and the spot and fill contracts entered into and shipped during this lower natural gas prices environment realized lower average plant gate price. Ammonia and UAN sales prices for the year ended December 31, 2007 decoupled from natural gas prices and increased sharply driven by increased demand for fertilizer due to the increased use of corn for the production of ethanol and an overall increase in prices for corn, wheat and soybeans, which are the primary row crops in our region. This increase in demand for nitrogen fertilizer has created an environment in which nitrogen fertilizer prices have disconnected from their traditional correlation to natural gas.

Cost of Product Sold Exclusive of Depreciation and Amortization. Cost of product sold exclusive of depreciation and amortization is primarily comprised of petroleum coke expense, hydrogen reimbursement and freight and distribution expenses. Cost of product sold excluding depreciation and amortization for the year ended December 31, 2007 was $13.0 million compared to $25.9 million for the year ended December 31, 2006. The decrease of $12.9 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was primarily the result of increased hydrogen reimbursement due to the transfer of hydrogen to our Petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit and reduced freight expense partially offset by an increase in petroleum coke costs.

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

Net Costs Associated with Flood. Nitrogen fertilizer net costs associated with flood for the year ended December 31, 2007 approximated $2.4 million as compared to none for the year ended December 31, 2006. Total gross costs recorded as a result of the physical damage to the fertilizer plant for the year ended December 31, 2007 were approximately $5.7 million. Included in the gross costs associated with the June/July

2007 flood were certain costs that are excluded from the accounts receivable from insurers of approximately $3.3 million at December 31, 2007, for which we believe collection is probable. The costs excluded from the accounts receivable from insurers were approximately $0.8 million recorded for depreciation for the temporarily idle facilities, $0.1 million of uninsured losses inside of our deductibles and $1.5 million of uninsured expenses.

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

Operating Income. Nitrogen fertilizer operating income was $46.6 million for the year ended December 31, 2007 as compared to $36.8 million for the year ended December 31, 2006. This increase of $9.8 million for the year ended December 31, 2007 as compared to the year ended December 31, 2006 was partially the result of an increase in plant gate prices ($34.4 million), partially offset by reductions in overall sales volumes ($31.0). In addition, a $12.9 million reduction in cost of product sold excluding depreciation and amortization due to increased hydrogen reimbursement and reduced freight expense partially offset by an increase in petroleum coke costs contributed to the positive variance in operating income during for the year ended December 31, 2007 compared to the year ended December 31, 2006. Partially offsetting the positive effects of plant gate prices and cost of product sold excluding depreciation and amortization was an increase in direct operating expenses associated with repairs and maintenance ($6.5 million), equipment rental ($0.6 million) environmental ($0.4 million), utilities ($0.3 million), and insurance ($0.3 million). These increases in direct operating expenses were partially offset by reductions in expenses associated with turnaround ($2.6 million), royalties and other expense ($1.1 million), reimbursed expense ($0.6 million), catalyst ($0.3 million), chemicals ($0.3 million) and slag disposal ($0.2 million).

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, 2008, we had cash, cash equivalents and short-term investments of $8.9 million. In addition, we had restricted cash of $34.6 million which was utilized to pay down the J. Aron deferral on January 2, 2009. As of December 31, 2008, we had no amounts outstanding under our revolving credit facility and aggregate availability of $100.1 million under our revolving credit facility.

As of December 31, 2008, our working capital and total stockholders equity were positively impacted by the mark to market accounting treatment of the Cash Flow Swap. The payable to swap counterparty included in the consolidated balance sheet at December 31, 2008 was approximately $62.4 million. The entire current portion of the payable to swap counterparty for the period ended December 31, 2008 represents the deferred payments due to J. Aron. The restricted cash at December 31, 2008 of $34.6 million was paid to J. Aron on January 2, 2009, resulting in a balance due to J. Aron of $27.8 million for the deferral. On March 2, 2009, the deferral obligation was paid in full, including accrued interest.

At December 31, 2008, funded long-term debt, including current maturities, totaled $484.3 million of tranche D term loans. Other commitments at December 31, 2008 included a $150.0 million funded letter of credit facility and a $150.0 million revolving credit facility. As of December 31, 2008, the commitment outstanding on the revolving credit facility was $49.9 million, including $0 million in borrowings, $3.3 million in letters of credit in support of certain environmental obligations, and $46.6 million in letters of credit to secure transportation services for crude oil.

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. Working capital at December 31, 2007 was $10.7 million, consisting of $570.2 million in current assets and $559.5 million in current liabilities.

Credit Facility

Our credit facility currently consists of Tranche D term loans with an outstanding balance of $484.3 million at December 31, 2008, a $150.0 million revolving credit facility, and a funded letter of credit facility of $150.0 million issued in support of the Cash Flow Swap.

The $484.3 million of tranche D term loans outstanding as of December 31, 2008 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.

The revolving loan facility of $150.0 million provides for direct cash borrowings for general corporate purposes and on a short-term basis. Letters of credit issued under the revolving loan facility are subject to a $75.0 million sub-limit. The revolving loan commitment expires on December 28, 2012. The borrower has an option to extend this maturity upon written notice to the lenders; however, the revolving loan maturity cannot be extended beyond the final maturity of the term loans, which is December 28, 2013. As of December 31, 2008, we had available $100.1 million under the revolving credit facility.

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

The credit facility incorporates the following pricing by facility type:

Tranche D term loans bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 4.50%, or, at the borrower s option, (b) LIBOR plus 5.50% (with step-downs to the prime rate/federal funds rate plus 4.25% or 4.00% or LIBOR plus 5.25% or 5.50%, respectively, upon achievement of certain rating conditions).

Revolving credit loans bear interest at either (a) the greater of the prime rate and the federal funds effective rate plus 0.5%, plus in either case 4.50%, or, at the borrower s option, (b) LIBOR plus 5.50% (with step-downs to the prime rate/federal funds rate plus 4.25% or 4.00% or LIBOR plus 5.25% or 5.00%, respectively, upon achievement of certain rating conditions). Revolving credit lenders receive commitment fees equal to the amount of undrawn revolving credit loans times .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.

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

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 applies for the year ending December 31, 2008 through the quarter ending September 30, 2009. This FIFO adjustment will 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 over the last few months 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 have been set at a minimum of 3.25% and 4.25%, respectively.

The amendment provides for more restrictive requirements. Among other things, CRLLC is subject to more stringent obligations under certain circumstances to make mandatory prepayments of loans. In addition, the amendment increased the percentage of excess cash flow during any fiscal year that must be used to prepay the loans and eliminated a basket which previously allowed CRLLC to pay dividends of up to $35.0 million per year.

The credit facility requires CRLLC to prepay outstanding loans, subject to certain exceptions. Some of the requirements, among other things, are as follows:

100% of the asset sale proceeds must be used to repay outstanding loans;

100% of the cash proceeds from the incurrence of specified debt obligations must be used to prepay outstanding loans; and,

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

Under the terms of our credit facility, the interest margin paid is subject to change based on changes in our leverage ratio and changes in our credit rating by either Standard & Poor s (S&P) or Moody s. S&P s recent announcement in February 2009 to place the Company on negative outlook resulted in an increase in our interest rate of 0.25% on amounts borrowed under our term loan facility, revolving credit facility and the $150.0 million funded letter of credit facility.

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 Cash Flow Swap or the Partnership s 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.

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The credit facility also requires CRLLC to maintain certain financial ratios as follows:

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

The computation of these ratios is governed by the specific terms of the credit facility and may not be comparable to other similarly titled measures computed for other purposes or by other companies. The minimum interest coverage ratio is the ratio of consolidated adjusted EBITDA to consolidated cash interest expense over a four quarter period. The maximum leverage ratio is the ratio of consolidated total debt to consolidated adjusted EBITDA over a four quarter period. The computation of these ratios requires a calculation of consolidated adjusted EBITDA. In general, under the terms of our credit facility, consolidated adjusted EBITDA is calculated by adding consolidated net income, consolidated interest expense, income taxes, depreciation and amortization, other non- cash expenses, any fees and expenses related to permitted acquisitions, any non-recurring expenses incurred in connection with the issuance of debt or equity, management fees, any unusual or non-recurring charges up to 7.5% of consolidated adjusted EBITDA, any net after-tax loss from disposed or discontinued operations, any incremental property taxes related to abatement non-renewal, any losses attributable to minority equity interests, 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, 2008, we were in compliance with our covenants under the credit facility.

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

	Year Ended December 31,		
Consolidated Financial Results	**2008**	**2007**	**2006**
		(in millions)	
Net income (loss)	$ 163.9	$ (67.6)	$ 191.6
Plus:			
Depreciation and amortization	82.2	68.4	51.0
Interest expense	40.3	61.1	43.9
Income tax expense (benefit)	63.9	(88.5)	119.8
Loss on extinguishment of debt	10.0	1.3	23.4
Funded letters of credit expenses and interest rate swap not included in interest expense	7.4	1.8	
Major scheduled turnaround expense	3.3	76.4	6.6
Unrealized (gain) or loss on derivatives, net	(247.9)	113.5	(128.5)
Non-cash compensation expense for equity awards	(17.2)	43.5	16.9
(Gain) or loss on disposition of fixed assets	5.8	1.3	1.2
Unusual or nonrecurring charges	12.5		
Property tax increases due to expiration of abatement	11.6		
FIFO loss(1)	102.5		

Minority interest in subsidiaries		(0.2)	
Management fees		11.7	2.3
Goodwill impairment	42.8		
Consolidated adjusted EBITDA	$ 281.1	$ 222.7	$ 328.2

(1) The 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 applies for the year ending December 31, 2008 and will apply through the quarter ending September 30, 2009.

In addition to the financial covenants previously mentioned, the credit facility restricts the capital expenditures of CRLLC and its subsidiaries to $125 million in 2009, $80 million in 2010, and $50 million in 2011 and thereafter. The capital expenditures covenant includes a mechanism for carrying over the excess of any previous year s capital expenditure limit. The capital expenditures limitation will not apply for any fiscal year commencing with fiscal year 2009 if CRLLC obtains a total leverage ratio of less than or equal to 1.25:1.00 for any quarter commencing with the quarter ended December 31, 2008. We believe the limitations on our capital expenditures imposed by the credit facility should allow us to meet our current capital expenditure needs. However, if future events require us or make it beneficial for us to make capital expenditures beyond those currently planned, we would need to obtain consent from the lenders under our credit facility.

The credit facility also contains customary events of default. The events of default include the failure to pay interest and principal when due, including fees and any other amounts owed under the credit facility, a breach of certain covenants under the credit facility, a breach of any representation or warranty contained in the credit facility, any default under any of the documents entered into in connection with the credit facility, the failure to pay principal or interest or any other amount payable under other debt arrangements in an aggregate amount of at least $20 million, a breach or default with respect to material terms under other debt arrangements in an aggregate amount of at least $20 million which results in the debt becoming payable or declared due and payable before its stated maturity, a breach or default under the Cash Flow Swap that would permit the holder or holders to terminate the Cash Flow Swap, events of bankruptcy, judgments and attachments exceeding $20 million, events relating to employee benefit plans resulting in liability in excess of $20 million, a change in control, the guarantees, collateral documents or the credit facility failing to be in full force and effect or being declared null and void, any guarantor repudiating its obligations, the failure of the collateral agent under the credit facility to have a lien on any material portion of the collateral, and any party under the credit facility (other than the agent or lenders under the credit facility) contesting the validity or enforceability of the credit facility.

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

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 receives net insurance proceeds related to the 2007 flood, the proceeds will be used to prepay the deferred amounts. The Goldman Sachs Funds and the Kelso Fund each agreed to guarantee one half of the deferred payment obligations.

As of December 31, 2008, the outstanding deferred payable was $62.4 million. 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 agreed to release the Goldman Sachs Funds and the Kelso Fund from any and all of their obligations to guarantee the deferred payment obligations.

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Capital Spending

We divide our capital spending needs into two categories: non-discretionary, which is either capitalized or expensed, and discretionary, which is capitalized. Non-discretionary capital spending, such as for planned turnarounds and other maintenance, is required to maintain safe and reliable operations or to comply with environmental, health and safety regulations. The total non-discretionary capital spending needs for our refinery business and nitrogen fertilizer business, including major scheduled turnaround expenses, were approximately $58.2 million in 2008, $217.5 million in 2007 and $169.7 million in 2006. We estimate that the total non-discretionary capital spending needs, including major scheduled turnaround expenses, of our refinery business and the nitrogen fertilizer business will be approximately $216.5 million in the aggregate over the three-year period beginning 2009. These estimates include, among other items, the capital costs necessary to comply with environmental regulations, including Tier II gasoline standards. As described above, our credit facilities limit the amount we can spend on capital expenditures.

Compliance with the Tier II gasoline and on-road diesel standards required us to spend approximately $38 million in 2008, $103 million during 2007 and approximately $133 million during 2006, and we estimate that compliance will require us to spend approximately $52 million in the aggregate between 2009 and 2011.

The following table sets forth our estimate for the next three years of non-discretionary spending, including expected major scheduled turnaround expenses, for our refinery business and the nitrogen fertilizer business for the years presented as of December 31, 2008. Capital spending for the nitrogen fertilizer business has been and will be determined by the managing general partner of the Partnership. The data contained in the table below represents our current plans, but these plans may change as a result of unforeseen circumstances and we may revise these estimates from time to time or not spend the amounts in the manner allocated below.

Petroleum Business

	2009	2010	2011
Environmental and safety capital needs	$ 36.1	$ 46.1	$ 30.7
Sustaining capital needs	17.1	10.5	16.4
	53.2	56.6	47.1
Major scheduled turnaround expenses	0.5	1.0	40.0
Total estimated non-discretionary spending	$ 53.7	$ 57.6	$ 87.1

Nitrogen Fertilizer Business

	2009	2010	2011
Environmental and safety capital needs	$ 1.9	$ 0.5	$ 2.1
Sustaining capital needs	5.3	3.8	0.7
	7.2	4.3	2.8
Major scheduled turnaround expenses		3.8	
Total estimated non-discretionary spending	$ 7.2	$ 8.1	$ 2.8

Combined

	2009	2010	2011
Environmental and safety capital needs	$ 38.0	$ 46.6	$ 32.8
Sustaining capital needs	22.4	14.3	17.1
	60.4	60.9	49.9
Major scheduled turnaround expenses	0.5	4.8	40.0
Total estimated non-discretionary spending	$ 60.9	$ 65.7	$ 89.9

We undertake discretionary capital spending based on the expected return on incremental capital employed. Discretionary capital projects generally involve an expansion of existing capacity, improvement in product yields, and/or a reduction in direct operating expenses. As of December 31, 2008, we had committed approximately $19 million towards discretionary capital spending in 2009.

The Partnership recently decided to suspend indefinitely any further development related to the previously announced $120 million UAN fertilizer plant expansion, as well as other smaller discretionary projects.

As a result of additional maintenance work performed during the 2007 flood recovery and subsequent maintenance outages, we have moved our 2010 refinery turnaround into 2011.

Cash Flows

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

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Net cash provided by (used in)			
Operating activities	$ 83.2	$ 145.9	$ 186.6
Investing activities	(86.5)	(268.6)	(240.2)
Financing activities	(18.3)	111.3	30.8
Net increase (decrease) in cash and cash equivalents	$ (21.6)	$ (11.4)	$ (22.8)

Cash Flows Provided by Operating Activities

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. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, 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. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the year ended December 31, 2007 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2007 (approximately two years and six months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash Flow Swap significantly decreased our Net Income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $240.9 million increase in the payable to swap counterparty. Other sources of cash from other working capital included $4.8 million from prepaid expenses and other current assets, $27.0 million from other current liabilities and $20.0 million in insurance proceeds. Reducing our operating cash flow for the year ended December 31, 2007 was $42.9 million use of cash related to changes in trade working capital. For the year ended December 31, 2007, accounts receivable increased $17.0 million and inventory increased by $85.0 million resulting in a net use of cash of $102.0 million. These uses of cash due to changes in trade working capital were partially offset by an increase in accounts payable, or a source of cash, of $59.1 million. Other primary uses of cash during the period include a $105.3 million increase in our insurance receivable related to the 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.

Net cash flows from operating activities for the year ended December 31, 2006 was $186.6 million. The positive cash flow from operating activities generated over this period was primarily driven by our strong operating environment and favorable changes in other assets and liabilities, partially offset by unfavorable changes in trade working capital and other working capital over the period. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net income for the year ended December 31, 2006 included both the realized loss and the unrealized gains on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of December 31, 2006 (approximately three years and six months) and the NYMEX crack spread that is the basis for the underlying swaps had declined, the unrealized gains on the Cash Flow Swap significantly increased our net income over this period. The impact of these unrealized gains on the Cash Flow Swap is apparent in the $147.0 million decrease in the payable to swap counterparty. Reducing our operating cash flow for the year ended December 31, 2006, was a $0.3 million use of cash related to an increase in trade working capital. For the year ended December 31, 2006, accounts receivable decreased approximately $1.9 million while inventory increase $7.2 million and accounts payable increased $5.0 million. Other primary uses of cash during the period include a $5.4 million increase in prepaid expenses and other current assets and a $37.0 million reduction in accrued income taxes. Offsetting these uses of cash was an $86.8 million increase in deferred income taxes primarily the result of the unrealized gain on the Cash Flow Swap and a $4.6 million increase in the other current liabilities.

Cash Flows Used In Investing Activities

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.

Net cash used in investing activities for the year ended December 31, 2007 was $268.6 million compared to $240.2 million for the year ended December 31, 2006. The increase in investing activities for the year ended

December 31, 2007 as compared to the year ended December 31, 2006 was the result of increased capital expenditures associated with various capital projects in our petroleum business.

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Cash Flows Provided by Financing Activities

Net cash used by 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 $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.

Net cash provided by financing activities for the year ended December 31, 2007 was $111.3 million as compared to net cash provided by financing activities of $30.8 million for the year ended December 31, 2006. The primary sources of cash for the year ended December 31, 2007 were obtained through $399.6 million of proceeds associated with our initial public offering. The primary uses of cash for the year ended December 31, 2007 was $335.8 million of long-term debt retirement and $2.5 million in payments of financing costs. The primary sources of cash for the year ended December 31, 2006 were obtained through a refinancing of the Successor s first and second lien credit facilities into a new long term debt credit facility of $1.075 billion, of which $775.0 million was outstanding as of December 31, 2006. The $775.0 million term loan under the credit facility was used to repay approximately $527.7 million in first and second lien debt outstanding, fund $5.5 million in prepayment penalties associated with the second lien credit facility and fund a $250.0 million cash distribution to CALLC. Other sources of cash included $20.0 million of additional equity contributions into CALLC, which was subsequently contributed to our operating subsidiaries, and $30.0 million of additional delayed draw term loans issued under the first lien credit facility. During this period, we also paid $1.7 million of scheduled principal payments on the first lien term loans.

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, 2008 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, 2008 and thereafter.

	Payments Due by Period (in millions)						
	Total	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Contractual Obligations							
Long-term debt(1)	$ 484.3	$ 4.8	$ 4.8	$ 4.7	$ 4.7	$ 465.3	$
Operating leases(2)	8.9	4.0	2.7	1.3	0.9		
Unconditional purchase obligations(3)	592.3	29.4	35.9	57.3	54.6	54.5	360.6
Environmental liabilities(4)	7.5	2.7	1.0	0.5	0.3	0.3	2.7
Funded letter of credit fees(5)	12.4	8.3	4.1				
Interest payments(6)	204.1	44.6	44.1	43.7	43.4	28.3	
Total	$ 1,309.5	$ 93.8	$ 92.6	$ 107.5	$ 103.9	$ 548.4	$ 363.3
Other Commercial Commitments							

Standby letters of credit(7)	$ 49.9	$	$	$	$	$	$

(1) Long-term debt amortization is based on the contractual terms of our credit facility. We may be required to amend our credit facility in connection with an offering by the Partnership. As of December 31, 2008, $484.3 million was outstanding under our credit facility. See Liquidity and Capital Resources Debt.

(2) The nitrogen fertilizer business leases various facilities and equipment, primarily railcars, under non-cancelable operating leases for various periods.

(3) The amount includes (1) commitments under several agreements in our petroleum operations related to pipeline usage, petroleum products storage and petroleum transportation and (2) commitments under an electric supply agreement with the city of Coffeyville.

(4) Environmental liabilities represents (1) our estimated payments required by federal and/or state environmental agencies related to closure of hazardous waste management units at our sites in Coffeyville and Phillipsburg, Kansas and (2) our estimated remaining costs to address environmental contamination resulting from a reported release of UAN in 2005 pursuant to the Sate of Kansas Voluntary Cleaning and Redevelopment Program. We also have other environmental liabilities which are not contractual obligations but which would be necessary for our continued operations. See Business Environmental Matters.

(5) This amount represents the total of all fees related to the funded letter of credit issued under our credit facility. The funded letter of credit is utilized as credit support for the Cash Flow Swap. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

(6) Interest payments are based on interest rates in effect at December 31, 2008 and assume contractual amortization payments.

(7) Standby letters of credit include $3.3 million of letters of credit issued in connection with environmental liabilities, and $46.6 million in letters of credit to secure transportation services for crude oil.

In addition to the amounts described in the above table, under the J. Aron deferral agreement, we agreed to make prepayments of $5.0 million for the quarters ending March 31, 2009 and June 30, 2009. In January and February 2009, we prepaid $46.4 million of the deferred obligation, reducing the total principal deferred obligation to $16.1 million. In addition, we paid off the outstanding principal balance of $16.1 million and accrued interest of $0.5 million on March 2, 2009.

Our ability to make payments on and to refinance our indebtedness, to fund planned capital expenditures and to satisfy our other capital and commercial commitments will depend on our ability to generate cash flow in the future. Our ability to refinance our indebtedness is also subject to the availability of the credit markets, which in recent periods have been extremely volatile. This, to a certain extent, is subject to refining spreads, fertilizer margins, receipt of distributions from the Partnership and general economic financial, competitive, legislative, regulatory and other factors that are beyond our control. Our business may not generate sufficient cash flow from operations, and future borrowings may not be available to us under our credit facility (or other credit facilities we may enter into in the future) in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may seek to sell additional assets to fund our liquidity needs but may not be able to do so. We may also need to refinance all or a portion of our indebtedness on or before maturity. We may not be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements as such term is defined within the rules and regulations of the SEC.

Recently Issued Accounting Standards

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* This statement will change the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedge items affect an entity s financial position, net earnings, and cash flows. As required, we adopted this statement as of January 1, 2009. We currently disclose many of the quantitative and qualitative disclosures required by SFAS 161.

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In February 2008, the FASB issued FASB Staff Position 157-2 which defers the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in an entity s financial statements on a recurring basis (at least annually). As required, we adopted SFAS 157 as of January 1, 2009. Management believes the adoption of SFAS 157 deferral provisions will not have a material impact on our financial position or earnings.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations.* This statement defines the acquirer as the entity that obtains control of one or more businesses in the business combination, establishes the acquisition date as the date that the acquirer achieves control and requires the acquirer to recognize the assets acquired, liabilities assumed and any noncontrolling interest at their fair values as of the acquisition date. This statement also requires that acquisition-related costs of the acquirer be recognized separately from the business combination and will generally be expensed as incurred. As required, we adopted this statement as of January 1, 2009. The impact of adopting SFAS 141R will be limited to any future business combinations for which the acquisition date is on or after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 must be applied prospectively. As required, we adopted this statement as of January 1, 2009. At the current time the most significant impact of SFAS 160 on our financial statements will be the classification of the noncontrolling interest on the Consolidated Balance Sheets as equity.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price) . The statement s provisions for financial assets and financial liabilities, which became effective January 1, 2008, had no material impact on our financial position or results of operations. At December 31, 2008, the only financial assets and liabilities that are measured at fair value on a recurring basis are our derivative instruments.

Critical Accounting Policies

We prepare our consolidated financial statements in accordance with GAAP. In order to apply these principles, management must make judgments, assumptions and estimates based on the best available information at the time. Actual results may differ based on the accuracy of the information utilized and subsequent events. Our accounting policies are described in the notes to our audited financial statements included elsewhere in this Report. Our critical accounting policies, which are described below, could materially affect the amounts recorded in our financial statements.

Goodwill

To comply with Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (the Statement or SFAS 142) we perform a test for goodwill impairment annually or more frequently in the event we determine that a triggering event has occurred. Our annual testing is performed as of November 1.

During the fourth quarter of 2008, there were severe disruptions in the capital and commodities markets that contributed to a significant decline in our common stock, thus causing our market capitalization to decline to a level substantially below our net book value. This substantial deterioration during the fourth quarter of 2008 would have triggered an evaluation for impairment had the annual testing not occurred during that period.

In accordance with SFAS 142 we identified our reporting units based upon our two key operating segments. These reporting units are our Petroleum and Nitrogen Fertilizer segments. These segments are unique reporting units that have discrete financial information available that management regularly reviews.

For 2008 we completed the Step 1 analysis as part of our annual testing required by SFAS 142 to determine if either reporting unit had potential goodwill impairment. The Step 1 analysis compares the estimated fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, the goodwill of the reporting unit is not considered impaired. The second step (Step 2) of the impairment test is unnecessary. Conversely, if the carrying amount of a reporting unit exceeds its fair value, the second step of the goodwill impairment test shall be performed to measure the amount of impairment, if any. As a result of this process it was determined that our Petroleum reporting unit had a carrying value of net assets that exceeded the calculated fair value indicating goodwill may be impaired and necessitating a Step 2 evaluation. The Step 1 evaluation of the Nitrogen reporting unit did not indicate impairment as the calculated fair value exceeded the carrying value of net assets.

The annual review of impairment was performed by comparing the carrying value of the applicable reporting unit to its estimated fair value. The valuation analysis used both income and market approaches as described below:

Income Approach: To determine fair value, we discounted the expected future cash flows for each reporting unit utilizing observable market data to the extent available. The discount rates used range from 18.3% to 22.8% representing the estimated weighted average costs of capital, which reflects the overall level of inherent risk involved in each reporting unit and the rate of return an outside investor would expect to earn.

Market-Based Approach: To determine the fair value of each reporting unit, we also utilized a market based approach. We used the guideline company method, which focuses on comparing our risk profile and growth prospects to select reasonably similar/guideline publicly traded companies.

We assigned an equal weighting of 50% to the result of both the income approach and market based approach based upon the reliability and relevance of the data used in each analysis. This weighting was deemed reasonable as the guideline public companies have a high-level of comparability with the respective reporting units and the projections used in the income approach were thoroughly prepared using up-to-date estimates.

As of the result of the potential impairment as indicated by Step 1 for our Petroleum reporting unit, we completed the second step of the impairment test. In Step 2, the fair values of each of the reporting unit s identifiable assets and liabilities are determined as they would be in a business combination accounted for under purchase accounting, and the excess of the deemed purchase price over the net fair value of all of the identifiable assets and liabilities represents the implied fair value of the goodwill of that reporting unit. If the carrying amount of that reporting unit s goodwill exceeds this implied fair value of goodwill, an impairment loss is recognized in the amount of that excess to reduce the carrying amount of goodwill to the implied fair value determined in the hypothetical purchase price allocation. As a result of carrying out Step 2, we determined the carrying value of goodwill assigned to the Petroleum reporting unit exceeded the implied fair value of the goodwill, and thus recorded a full impairment charge of $42,806,000.

In order to evaluate the reasonableness of the conclusions reached we compared our conclusions with the implied market enterprise value of the Company as of the valuation date. In doing so we determined that the sum of the market value of invested capital for the Petroleum and Nitrogen Fertilizer segment exceeded the Company s market capitalization plus the book value of debt by approximately 10.2%. We identified several factors that have led to the difference including (i) our common stock is thinly traded and significant fluctuations in our stock can occur as a result (ii) the refining industry outlook shifted dramatically in the fourth quarter of the year and (iii) a hypothetical buyer may have the ability to take advantage of synergies and other benefits of control and as such a control premium would be expected. As part of our analysis we identified one controlling transaction completed in 2008 with a 30 day premium of 14.6% according to MergerStat. Over the last four years reported premiums have ranged from 8.7% to 62.2%. Recent market conditions and a continued expected downturn in the economy has caused significant downward pressure on equity prices that are not reflective of the fair value of the reporting units from an enterprise level. We considered the sum of our conclusions to be within a reasonable range of the implied market enterprise value based on the stock price.

Long-Lived Assets

We calculate depreciation and amortization on a straight-line basis over the estimated useful lives of the various classes of depreciable assets. When assets are placed in service, we make estimates of what we believe are their reasonable useful lives. The Company accounts for impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* In accordance with SFAS 144, the Company reviews long-lived assets (excluding goodwill, intangible assets with indefinite lives, and deferred tax assets) for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In connection with our goodwill impairment analysis described above, we performed a review of our long-lived assets and noted the estimated undiscounted cash flows supported the carrying value of these assets, and therefore, no impairment was recognized. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future net cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future net cash flows, an impairment charge is recognized for the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of their carrying value or fair value less cost to sell. No impairment charges were recognized for any of the periods presented.

Derivative Instruments and Fair Value of Financial Instruments

We use futures contracts, options, and forward contracts primarily to reduce exposure to changes in crude oil prices, finished goods product prices and interest rates to provide economic hedges of inventory positions and anticipated interest payments on long term-debt. Although management considers these derivatives economic hedges, the Cash Flow Swap and our other derivative instruments do not qualify as hedges for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and accordingly are recorded at fair value in the balance sheet. Changes in the fair value of these derivative instruments are recorded into earnings as a component of other income (expense) in the period of change. The estimated fair values of forward and swap contracts are based on quoted market prices and assumptions for the estimated forward yield curves of related commodities in periods when quoted market prices are unavailable. The Company recorded net gains (losses) from derivative instruments of $125.3 million, $(282.0) million and $94.5 million in gain (loss) on derivatives, net for the fiscal years ended December 31, 2008, 2007 and 2006, respectively.

As of December 31, 2008, a $1.00 change in quoted prices for the crack spreads utilized in the Cash Flow Swap would result in a $17.7 million change to the fair value of derivative commodity position and would impact our gain (loss) on derivatives, net on the Consolidated Statements of Operations by the same amount.

Share-Based Compensation

For the years ended December 31, 2008, 2007, and 2006, we account for share-based compensation in accordance with SFAS No. 123(R), *Share-Based Payment.* SFAS 123(R) requires that compensation costs relating to share-based payment transactions be recognized in a company s financial statements. SFAS 123(R) applies to transactions in which an entity exchanges its equity instruments for goods or services and also may apply to liabilities an entity incurs for goods or services that are based on the fair value of those equity instruments.

The Company accounts for awards under its Phantom Unit Plans as liability based awards. In accordance with FAS 123(R), the expense associated with these awards for 2008 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 the accounting guidance in EITF 00-12 and EITF 96-18. In accordance with that accounting guidance, the expense associated with the awards is based on the current fair value of the awards which is derived in 2008 under the same methodology as the Phantom Unit Plan, as remeasured at each reporting date until the awards vest. Prior to October 2007, the expense associated with the override units was based on the original grant date fair value of the awards. For the year ending December 31, 2008, we reduced compensation expense by $43.3 million, associated with the phantom and override unit share-based compensation awards. For the years ending December 31, 2007 and December 31, 2006, we increased compensation expense by $43.5 million and $12.6 million, respectively, associated with the phantom and override unit share-based compensation awards.

Assuming the fair value of our share-based awards changed by $1.00, our compensation expense would increase or decrease by approximately $1.3 million.

Income Taxes

We provide for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* and FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB No. 109.* We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets and if we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the deferred tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments which requires numerous judgments and assumptions. We record contingent income tax liabilities, interest and penalties, as provided for in FIN 48, based on our estimate as to whether, and the extent to which, additional taxes may be due.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

The risk inherent in our market risk sensitive instruments and positions is the potential loss from adverse changes in commodity prices and interest rates. None of our market risk sensitive instruments are held for trading.

Commodity Price Risk

Our petroleum business, as a manufacturer of refined petroleum products, and the nitrogen fertilizer business, as a manufacturer of nitrogen fertilizer products, all of which are commodities, has exposure to market pricing for products sold in the future. In order to realize value from our processing capacity, a positive spread between the cost of raw materials and the value of finished products must be achieved (i.e., gross margin or crack spread). The physical commodities that comprise our raw materials and finished goods are typically bought and sold at a spot or index price that can be highly variable.

We use a crude oil purchasing intermediary which allows us to take title and price of our crude oil at the refinery, as opposed to the crude origination point, reducing our risk associated with volatile commodity prices by shortening the commodity conversion cycle time. The commodity conversion cycle time refers to the time elapsed between raw material acquisition and the sale of finished goods. In addition, we seek to reduce the variability of commodity price exposure by engaging in hedging strategies and transactions that will serve to protect gross margins as forecasted in the annual operating plan. Accordingly, we use financial derivatives to economically hedge future cash flows (i.e., gross margin or crack spreads) and product inventories. With regard to our hedging activities, we may enter into, or have entered into, derivative instruments which serve to:

- lock in or fix a percentage of the anticipated or planned gross margin in future periods when the derivative market offers commodity spreads that generate positive cash flows;
- hedge the value of inventories in excess of minimum required inventories; and,
- manage existing derivative positions related to change in anticipated operations and market conditions.

Further, we intend to engage only in risk mitigating activities directly related to our businesses.

Basis Risk. The effectiveness of our derivative strategies is dependent upon the correlation of the price index utilized for the hedging activity and the cash or spot price of the physical commodity for which price risk is being mitigated. Basis risk is a term we use to define that relationship. Basis risk can exist due to several factors including time or location differences between the derivative instrument and the underlying physical commodity. Our selection of the appropriate index to utilize in a hedging strategy is a prime consideration in our basis risk exposure.

Examples of our basis risk exposure are as follows:

- *Time Basis* In entering over-the-counter swap agreements, the settlement price of the swap is typically the average price of the underlying commodity for a designated calendar period. This settlement price is based on the assumption that the underlying physical commodity will price ratably over the swap period. If the commodity does not move ratably over the periods than weighted average physical prices will be weighted differently than the swap price as the result of timing.
- *Location Basis* In hedging NYMEX crack spreads, we experience location basis as the settlement of NYMEX refined products (related more to New York Harbor cash markets) which may be different than the prices of refined products in our Group 3 pricing area.

Price and Basis Risk Management Activities. The most significant derivative position we have is our Cash Flow Swap. The Cash Flow Swap, for which the underlying commodity is the crack spread, enabled us to lock in a margin on the spread between the price of crude oil and price of refined products at the execution date of the agreement. We may look for opportunities to reduce the effective position of the Cash Flow Swap by buying either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps. In addition, we may sell forward crack spreads when opportunities exist to lock in a margin.

In the event our inventories exceed our target base level of inventories, we may enter into commodity derivative contracts to manage our price exposure to our inventory positions that are in excess of our base level. Excess inventories are typically the result of plant operations such as a turnaround or other plant maintenance. The commodity derivative contracts are either exchange-traded contracts in the form of futures contracts or over-the-counter contracts in the form of commodity price swaps.

To reduce the basis risk between the price of products for Group 3 and that of the NYMEX associated with selling forward derivative contracts for NYMEX crack spreads, we may enter into basis swap positions to lock the price difference. If the difference between the price of products on the NYMEX and Group 3 (or some other price benchmark as we may deem appropriate) is different than the value contracted in the swap, then we will receive from or owe to the counterparty the difference on each unit of product contracted in the swap, thereby completing the locking of our margin. An example of our use of a basis swap is in the winter heating oil season. The risk associated with not hedging the basis when using NYMEX forward contracts to fix future margins is if the crack spread increases based on prices traded on NYMEX while Group 3 pricing remains flat or decreases then we would be in a position to lose money on the derivative position while not earning an offsetting additional margin on the physical position based on the Group 3 pricing.

On December 31, 2008, we had the following open commodity derivative contracts whose unrealized gains and losses are included in gain (loss) on derivatives in the consolidated statements of operations:

Our petroleum segment holds commodity derivative contracts in the form of the Cash Flow Swap for the period from July 1, 2005 to June 30, 2010 with J. Aron, a subsidiary of The Goldman Sachs Group, Inc. and a related party of ours. The Cash Flow Swap consists of swap agreements originally executed on June 16, 2005 in conjunction with the Subsequent Acquisition of Immediate Predecessor and required under the terms of our long-term debt agreements. These agreements were subsequently assigned from CALLC to CRLLC on June 24, 2005. The total notional quantities on the date of execution were 100,911,000 barrels of crude oil, 2,348,802,750 gallons of unleaded gasoline and 1,889,459,250 gallons of heating oil. Pursuant to these swaps, we receive a fixed price with respect to the heating oil and the unleaded gasoline while we pay a fixed price with respect to crude oil. In June 2006, a subsequent swap was entered into with J. Aron to effectively reduce our unleaded notional quantity and increase our heating oil notional quantity by 229,671,750 gallons over the period July 2, 2007 to June 30, 2010. Additionally, several other swaps were entered into with J. Aron to adjust effective net notional amounts of the aggregate position to better align with actual production volumes. The swap agreements were executed at the prevailing market rate at the time of execution and management believed the swap agreements would provide an economic hedge on future transactions. At December 31, 2008 the net notional open amounts under these swap agreements were 17,696,250 barrels of crude oil, 371,621,250 gallons of heating oil and 371,621,250 gallons of unleaded gasoline. The purpose of these contracts is to economically hedge 8,848,125 barrels of heating oil crack spreads, the price spread between crude oil and heating oil, and 8,848,125 barrels of unleaded gasoline crack spreads, the price spread between crude oil and unleaded gasoline. These open contracts had a total unrealized net gain at December 31, 2008 of approximately $40.9 million.

From time to time, our petroleum segment also holds various NYMEX positions through Merrill Lynch, Pierce, Fenner & Smith Incorporated. At December 31, 2008, we had no open contracts outstanding.

Interest Rate Risk

As of December 31, 2008, all of our $484.3 million of outstanding term debt was at floating rates. Although borrowings under our revolving credit facility are at floating rates based on prime, as of December 31, 2008, we had no outstanding revolving debt. An increase of 1.0% in the LIBOR rate would result in an increase in our interest expense of approximately $4.9 million per year.

In an effort to mitigate the interest rate risk highlighted above and as required under our then-existing first and second lien credit agreements, we entered into several interest rate swap agreements in 2005. These swap agreements were entered into with counterparties that we believe to be creditworthy. Under the swap agreements, we pay fixed rates and receive floating rates based on the three-month LIBOR rates, with payments calculated on the notional amounts set forth in the table below. The interest rate swaps are settled quarterly and marked to market at each reporting date.

Notional Amount	Effective Date	Termination Date	Fixed Rate
$250.0 million	March 31, 2008	March 30, 2009	4.195%
$180.0 million	March 31, 2009	March 30, 2010	4.195%
$110.0 million	March 31, 2010	June 29, 2010	4.195%

We have determined that these interest rate swaps do not qualify as hedges for hedge accounting purposes. Therefore, changes in the fair value of these interest rate swaps are included in income in the period of change. Net realized and unrealized gains or losses are reflected in the gain (loss) for derivative activities at the end of each period. For the year ended December 31, 2008, 2007 and 2006 we had approximately ($7.5 million), ($4.8 million) and $3.7 million of net realized and unrealized losses on these interest rate swaps.

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

CVR Energy, Inc. and Subsidiaries

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
CVR Energy, Inc.:

We have audited the accompanying consolidated balance sheets of CVR Energy, Inc. and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders equity/members equity, and cash flows for each of the years in the three-year period ended December 31, 2008. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of CVR Energy, Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 12, 2009 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Kansas City, Missouri
March 12, 2009

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
CVR Energy, Inc.:

We have audited CVR Energy, Inc. and subsidiaries (the Company s) internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report On Internal Control Over Financial Reporting under Item 9A. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of CVR Energy, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders equity/members equity, and cash flows for each of the years in the three-year period ended December 31, 2008, and our report dated March 12, 2009 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Kansas City, Missouri
March 12, 2009

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CVR Energy, Inc. and Subsidiaries

CONSOLIDATED BALANCE SHEETS

	December 31, 2008		December 31, 2007	
	(in thousands, except share data)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	8,923	$	30,509
Restricted cash		34,560		
Accounts receivable, net of allowance for doubtful accounts of $4,128 and $391, respectively		33,316		86,546
Inventories		148,424		254,655
Prepaid expenses and other current assets		37,583		14,186
Receivable from swap counterparty		32,630		
Insurance receivable		11,756		73,860
Income tax receivable		40,854		31,367
Deferred income taxes		25,365		79,047
Total current assets		373,411		570,170
Property, plant, and equipment, net of accumulated depreciation		1,178,965		1,192,174
Intangible assets, net		410		473
Goodwill		40,969		83,775
Deferred financing costs, net		3,883		7,515
Receivable from swap counterparty		5,632		
Insurance receivable		1,000		11,400
Other long-term assets		6,213		2,849
Total assets	$	1,610,483	$	1,868,356
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Current portion of long-term debt	$	4,825	$	4,874
Note payable and capital lease obligations		11,543		11,640
Payable to swap counterparty		62,375		262,415
Accounts payable		105,861		182,225
Personnel accruals		10,350		36,659
Accrued taxes other than income taxes		13,841		14,732
Deferred revenue		5,748		13,161
Other current liabilities		30,366		33,820
Total current liabilities		244,909		559,526
Long-term liabilities:				
Long-term debt, less current portion		479,503		484,328
Accrued environmental liabilities		4,240		4,844

Deferred income taxes	289,150	286,986
Other long-term liabilities	2,614	1,122
Payable to swap counterparty		88,230
Total long-term liabilities	775,507	865,510
Commitments and contingencies		
Minority interest in subsidiary	10,600	10,600
Stockholders equity		
Common Stock $0.01 par value per share, 350,000,000 shares authorized; 86,243,745 and 86,141,291 shares issued and outstanding at December 31, 2008 and 2007, respectively	862	861
Additional paid-in-capital	441,170	458,359
Retained earnings (deficit)	137,435	(26,500)
Total stockholders equity	579,467	432,720
Total liabilities and stockholders equity	$ 1,610,483	$ 1,868,356

See accompanying notes to consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2008	2007	2006
	(in thousands, except share data)		
Net sales	$ 5,016,103	$ 2,966,864	$ 3,037,567
Operating costs and expenses:			
Cost of product sold (exclusive of depreciation and amortization)	4,461,808	2,308,740	2,443,375
Direct operating expenses (exclusive of depreciation and amortization)	237,469	276,137	198,980
Selling, general and administrative expenses (exclusive of depreciation and amortization)	35,239	93,122	62,600
Net costs associated with flood	7,863	41,523	
Depreciation and amortization	82,177	60,779	51,004
Goodwill impairment	42,806		
Total operating costs and expenses	4,867,362	2,780,301	2,755,959
Operating income	148,741	186,563	281,608
Other income (expense):			
Interest expense and other financing costs	(40,313)	(61,126)	(43,880)
Interest income	2,695	1,100	3,450
Gain (loss) on derivatives, net	125,346	(281,978)	94,493
Loss on extinguishment of debt	(9,978)	(1,258)	(23,360)
Other income (expense), net	1,355	356	(900)
Total other income (expense)	79,105	(342,906)	29,803
Income (loss) before income taxes and minority interest in subsidiaries	227,846	(156,343)	311,411
Income tax expense (benefit)	63,911	(88,515)	119,840
Minority interest in loss of subsidiaries		210	
Net income (loss)	$ 163,935	$ (67,618)	$ 191,571
Net earnings (loss) per share			
Basic	$ 1.90		
Diluted	$ 1.90		
Weighted average common shares outstanding:			
Basic	86,145,543		
Diluted	86,224,209		
Unaudited Pro Forma Information (Note 12):			
Net earnings (loss) per share:			
Basic		$ (0.78)	$ 2.22

Diluted	$ (0.78)	$ 2.22
Weighted average common shares outstanding:		
Basic	86,141,291	86,141,291
Diluted	86,141,291	86,158,791

See accompanying notes to consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY/MEMBERS EQUITY

	Management Voting Common Units Subject to Redemption		Note Receivable from Management Unit Holder	Total
	Units	Dollars	Dollars	Dollars
	(in thousands, except unit/share data)			
Balance at December 31, 2005	227,500	$ 4,172	$ (500)	$ 3,672
Payment of note receivable			150	150
Forgiveness of note receivable			350	350
Adjustment to fair value for management common units		4,240		4,240
Prorata reduction of management common units outstanding	(26,437)			
Distributions to management on common units		(3,119)		(3,119)
Net income allocated to management common units		1,688		1,688
Balance at December 31, 2006	201,063	6,981		6,981
Adjustment to fair value for management common units		2,037		2,037
Net loss allocated to management common units		(362)		(362)
Change from partnership to corporate reporting structure	(201,063)	(8,656)		(8,656)
Balance at December 31, 2007		$	$	$

See accompanying notes to consolidated financial statements.

CVR Energy, Inc. and Subsidiaries

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

	Voting Common Units		Management Nonvoting Override Operating Units		Management Nonvoting Override Value Units		Total
	Units	Dollars	Units	Dollars	Units	Dollars	Dollars
	(in thousands, except unit/share data)						
Balance at December 31, 2005	23,588,500	$ 114,831	919,630	$ 602	1,839,265	$ 395	$ 115,828
Issuance of 2,000,000 common units for cash	2,000,000	20,000					20,000
Recognition of share-based compensation expense related to override units				1,161		695	1,856
Adjustment to fair value for management common units		(4,240)					(4,240)
Prorata reduction of common units outstanding	(2,973,563)						
Issuance of 72,492 non-vested operating override units			72,492				
Issuance of 144,966 non-vested value override units					144,966		
Distributions to common unit holders		(246,881)					(246,881)
Net income allocated to		189,883					189,883

common units							
Balance at December 31, 2006	22,614,937	73,593	992,122	1,763	1,984,231	1,090	76,446
Recognition of share-based compensation expense related to override units				1,017		701	1,718
Adjustment to fair value for management common units		(2,037)					(2,037)
Adjustment to fair value for minority interest		(1,053)					(1,053)
Reversal of minority interest fair value adjustments upon redemption of the minority interest		1,053					1,053
Net loss allocated to common units		(40,756)					(40,756)
Change from partnership to corporate reporting structure	(22,614,937)	(30,800)	(992,122)	(2,780)	(1,984,231)	(1,791)	(35,371)
Balance at December 31, 2007		$		$		$	$

See accompanying notes to consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

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

	Common Stock				
	Shares Issued	Amount	Additional Paid-In Capital	Retained Deficit	Total
	(in thousands, except unit/share data)				
Balance at January 1, 2007		$	$	$	$
Change from partnership to corporate reporting structure	62,866,720	629	43,398		44,027
Issuance of common stock in exchange for minority interest of related party	247,471	2	4,700		4,702
Cash dividend declared			(10,600)		(10,600)
Public offering of common stock, net of stock issuance costs of $39,874,000	22,917,300	229	395,326		395,555
Purchase of common stock by employees through share purchase program	82,700	1	1,570		1,571
Share-based compensation			23,399		23,399
Issuance of common stock to employees	27,100		566		566
Net loss				(26,500)	(26,500)
Balance at December 31, 2007	86,141,291	861	458,359	(26,500)	432,720
Share-based compensation			(17,789)		(17,789)
Issuance of common stock to directors	96,620	1	399		400
Vesting of non-vested stock awards	5,834		201		201
Net income				163,935	163,935
Balance at December 31, 2008	86,243,745	$ 862	$ 441,170	$ 137,435	$ 579,467

See accompanying notes to consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 163,935	$ (67,618)	$ 191,571
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	82,177	68,406	51,005
Provision for doubtful accounts	3,737	15	100
Amortization of deferred financing costs	1,991	2,778	3,337
Loss on disposition of fixed assets	5,795	1,272	1,188
Loss on extinguishment of debt	9,978	1,258	23,360
Forgiveness of note receivable			350
Share-based compensation	(42,523)	44,083	16,905
Write off of CVR Energy, Inc. debt offering costs	1,567		
Write off of CVR Partners, LP initial public offering costs	2,539		
Minority interest in loss of subsidiaries		(210)	
Goodwill impairment	42,806		
Changes in assets and liabilities:			
Restricted cash	(34,560)		
Accounts receivable	49,493	(16,972)	1,871
Inventories	97,989	(84,980)	(7,157)
Prepaid expenses and other current assets	(19,064)	4,848	(5,384)
Insurance receivable	(1,681)	(105,260)	
Insurance proceeds for flood	74,185	20,000	
Other long-term assets	(3,751)	3,246	1,971
Accounts payable	(59,392)	59,110	5,005
Accrued income taxes	(9,487)	732	(37,039)
Deferred revenue	(7,413)	4,349	(3,218)
Other current liabilities	(5,319)	27,027	4,592
Payable to swap counterparty	(326,532)	240,944	(147,021)
Accrued environmental liabilities	(604)	(551)	(1,614)
Other long-term liabilities	1,492	1,122	
Deferred income taxes	55,846	(57,684)	86,770
Net cash provided by operating activities	83,204	145,915	186,592
Cash flows from investing activities:			
Capital expenditures	(86,458)	(268,593)	(240,225)
Net cash used in investing activities	(86,458)	(268,593)	(240,225)
Cash flows from financing activities:			

Revolving debt payments	(453,200)	(345,800)	(900)
Revolving debt borrowings	453,200	345,800	900
Proceeds from issuance of long-term debt		50,000	805,000
Principal payments on long-term debt	(4,874)	(335,797)	(529,438)
Payment of capital lease obligations	(940)		
Payment of financing costs	(8,522)	(2,491)	(9,364)
Deferred costs of CVR Partners initial public offering	(2,429)		
Deferred costs of CVR Energy convertible debt offering	(1,567)		
Prepayment penalty on extinguishment of debt			(5,500)
Payment of note receivable			150
Issuance of members equity			20,000
Net proceeds from sale of common stock		399,556	
Distribution of members equity		(10,600)	(250,000)
Sale of managing general partnership interest		10,600	
Net cash provided by (used in) financing activities	(18,332)	111,268	30,848
Net decrease in cash and cash equivalents	(21,586)	(11,410)	(22,785)
Cash and cash equivalents, beginning of period	30,509	41,919	64,704
Cash and cash equivalents, end of period	$ 8,923	$ 30,509	$ 41,919
Supplemental disclosures			
Cash paid for income taxes, net of refunds (received)	$ 17,551	$ (31,563)	$ 70,109
Cash paid for interest	$ 46,172	$ 56,886	$ 51,854
Non-cash investing and financing activities:			
Step-up in basis in property for exchange of common stock for minority interest, net of deferred taxes of $388,518	$	$ 586	$
Accrual of construction in progress additions	$ (16,972)	$ (15,268)	$ 45,991
Assets acquired through capital lease	$ 4,827	$	$

See accompanying notes to consolidated financial statements.

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and History of the Company

Organization

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

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

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

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

Initial Public Offering of CVR Energy, Inc.

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

The net proceeds to CVR from the initial public offering were approximately $408,480,000, after deducting underwriting discounts and commissions, but before deduction of offering expenses. The Company also incurred approximately $11,354,000 of other costs related to the initial public offering. The net proceeds from this offering were used to repay $280,000,000 of term debt under CRLLC s credit facility and to repay all indebtedness under CRLLC s $25,000,000 unsecured facility and $25,000,000 secured facility, including related accrued interest through the date of repayment of approximately $5,939,000. Additionally, $50,000,000 of net proceeds was used to repay outstanding indebtedness under the revolving credit facility under CRLLC s credit facility.

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

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

247,471 shares of CVR common stock in exchange for shares that he owned of Refining Holdco and CNF. The shares were fully vested and were exchanged at fair market value.

The Company also issued 27,100 shares of common stock to its employees on October 24, 2007 in connection with the initial public offering. The compensation expense recorded in the fourth quarter of 2007 was $566,000 related to shares issued. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, which does not include the non-vested shares issued noted below.

On October, 24, 2007, 17,500 shares of non-vested common stock having a value of $365,000 at the date of grant were issued to outside directors. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have dividend and voting rights with respect to these shares from the date of grant. The fair value of each share of non-vested common stock was measured based on the market price of the common stock as of the date of grant and is being amortized over the respective vesting periods. One-third of the non-vested award vested on October 24, 2008, one-third will vest on October 24, 2009, and the final one-third will vest on October 24, 2010.

Options to purchase 10,300 shares of common stock at an exercise price of $19.00 per share were granted to outside directors on October 22, 2007. These awards vest over a three year service period. Fair value was measured using an option-pricing model at the date of grant.

Nitrogen Fertilizer Limited Partnership

In conjunction with the consummation of CVR s initial public offering in 2007, CVR transferred CRNF, its nitrogen fertilizer business, to a newly created limited partnership (Partnership) in exchange for a managing general partner interest (managing GP interest), a special general partner interest (special GP interest , represented by special GP units) and a de minimis limited partner interest (LP interest , represented by special LP units). This transfer was not considered a business combination as it was a transfer of assets among entities under common control and, accordingly, balances were transferred at their historical cost. CVR concurrently sold the managing GP interest to an entity owned by its controlling stockholders and senior management at fair market value. The board of directors of CVR determined, after consultation with management, that the fair market value of the managing general partner interest was $10,600,000. This interest has been reflected as minority interest in the consolidated balance sheet at December 31, 2008 and 2007.

CVR owns all of the interests in the Partnership (other than the managing general partner interest and the associated incentive distribution rights (IDRs)) and is entitled to all cash distributed by the Partnership, except with respect to IDRs. The managing general partner is not entitled to participate in Partnership distributions except with respect to its IDRs, which entitle the managing general partner to receive increasing percentages (up to 48%) of the cash the Partnership distributes in excess of $0.4313 per unit in a quarter. However, the Partnership is not permitted to make any distributions with respect to the IDRs until the aggregate Adjusted Operating Surplus, as defined in the amended and restated partnership agreement, generated by the Partnership through December 31, 2009 has been distributed in respect of the units held by CVR and any common units issued by the Partnership if it elects to pursue an initial public offering. In addition, the Partnership and its subsidiaries are currently guarantors under CRLLC s credit facility. There will be no distributions paid with respect to the IDRs for so long as the Partnership or its subsidiaries are guarantors under the credit facility.

The Partnership is operated by CVR s senior management pursuant to a services agreement among CVR, the managing general partner, and the Partnership. The Partnership is managed by the managing general partner and, to the extent described below, CVR, as special general partner. As special general partner of the Partnership, CVR has joint management rights regarding the appointment, termination, and compensation of the chief executive officer and chief financial officer of the managing general partner, has the right to

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

designate two members of the board of directors of the managing general partner, and has joint management rights regarding specified major business decisions relating to the Partnership. CVR, the Partnership, and the managing general partner also entered into a number of agreements to regulate certain business relations between the partners.

At December 31, 2008, the Partnership had 30,333 special LP units outstanding, representing 0.1% of the total Partnership units outstanding, and 30,303,000 special GP interests outstanding, representing 99.9% of the total Partnership units outstanding. In addition, the managing general partner owned the managing general partner interest and the IDRs. The managing general partner contributed 1% of CRNF s interest to the Partnership in exchange for its managing general partner interest and the IDRs.

In accordance with the Contribution, Conveyance, and Assumption Agreement, by and between the Partnership and the partners, dated as of October 24, 2007, if an initial private or public offering of the Partnership is not consummated by October 24, 2009, the managing general partner of the Partnership can require the Company to purchase the managing GP interest. This put right expires on the earlier of (1) October 24, 2012 or (2) the closing of the Partnership s initial private or public offering. If the Partnership s initial private or public offering is not consummated by October 24, 2012, the Company has the right to require the managing general partner to sell the managing GP interest to the Company. This call right expires on the closing of the Partnership s initial private or public offering. In the event of an exercise of a put right or a call right, the purchase price will be the fair market value of the managing GP interest at the time of the purchase determined by an independent investment banking firm selected by the Company and the managing general partner.

On February 28, 2008, the Partnership filed a registration statement with the Securities and Exchange Commission (SEC) to effect an initial public offering of its common units representing limited partner interests. On June 13, 2008, the Company announced that the managing general partner of the Partnership had decided to postpone, indefinitely, the Partnership s initial public offering due to then-existing market conditions for master limited partnerships. The Partnership, subsequently, withdrew the registration statement.

As of December 31, 2008, the Partnership had distributed $50,000,000 to CVR.

(2) Summary of Significant Accounting Policies

Principles of Consolidation

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

Cash and Cash Equivalents

For purposes of the consolidated statements of cash flows, CVR considers all highly liquid money market accounts and debt instruments with original maturities of three months or less to be cash equivalents.

Restricted Cash

In December 2008, CVR had $34,560,000 in restricted cash. In connection with the cash flow swap deferral agreement dated October 11, 2008, the Company was required to use these funds to be applied to the outstanding balance owed to the swap counterparty by January 2, 2009.

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Accounts Receivable

CVR grants credit to its customers. Credit is extended based on an evaluation of a customer s financial condition; generally, collateral is not required. Accounts receivable are due on negotiated terms and are stated at amounts due from customers, net of an allowance for doubtful accounts. Accounts outstanding longer than their contractual payment terms are considered past due. CVR determines its allowance for doubtful accounts by considering a number of factors, including the length of time trade accounts are past due, the customer s ability to pay its obligations to CVR, and the condition of the general economy and the industry as a whole. CVR writes off accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. Amounts collected on accounts receivable are included in net cash provided by operating activities in the Consolidated Statements of Cash Flows. At December 31, 2008, there were no customers that represented individually more than 10% of CVR s total receivable balance. At December 31, 2007, two customers individually represented greater than 10% and, collectively, 29% of the total accounts receivable balance. The largest concentration of credit for any one customer at December 31, 2008 and December 31, 2007 was approximately 9% and 15%, respectively, of the accounts receivable balance.

Inventories

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

Prepaid Expenses and Other Current Assets

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

Property, Plant, and Equipment

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

Asset	**Range of Useful Lives, in Years**

Improvements to land	15 to 20
Buildings	20 to 30
Machinery and equipment	5 to 30
Automotive equipment	5
Furniture and fixtures	3 to 7

Our leasehold improvements and assets held under capital leases are depreciated or amortized on the straight-line method over the shorter of the contractual lease term or the estimated useful life. Assets under

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

capital leases are stated at the present value of minimum lease payments. Expenditures for routine maintenance and repair costs are expenses when incurred. Such expenses are reported in direct operating expenses (exclusive of depreciation and amortization) in the Company s consolidated statements of operations.

Goodwill and Intangible Assets

Goodwill represents the excess of the cost of an acquired entity over the fair value of the assets acquired less liabilities assumed. Intangible assets are assets that lack physical substance (excluding financial assets). Goodwill acquired in a business combination and intangible assets with indefinite useful lives are not amortized, and intangible assets with finite useful lives are amortized. Goodwill and intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset might be impaired. CVR uses November 1 of each year as its annual valuation date for the impairment test. The annual review of impairment is performed by comparing the carrying value of the applicable reporting unit to its estimated fair value. The estimated fair value is derived using a combination of the discounted cash flow analysis and market approach. Our reporting units are defined as operating segments due to each operating segment containing only one component. As such all goodwill impairment testing is done at each operating segment. During the fourth quarter of 2008, we recognized an impairment charge of $42,806,000 associated with the entire goodwill of the petroleum segment.

Deferred Financing Costs

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

Planned Major Maintenance Costs

The direct-expense method of accounting is used for planned major maintenance activities. Maintenance costs are recognized as expense when maintenance services are performed. During the year ended December 31, 2008, the Coffeyville nitrogen plant completed a major scheduled turnaround. Costs of approximately $3,343,000 associated with the turnaround are included in direct operating expenses (exclusive of depreciation and amortization). The Coffeyville refinery completed a major scheduled turnaround in 2007. Costs of approximately $76,393,000 and $3,984,000, associated with the 2007 turnaround, were included in direct operating expenses (exclusive of depreciation and amortization) for the year ended December 31, 2007 and December 31, 2006, respectively. During the year ended December 31, 2006, the Coffeyville nitrogen plant completed a major scheduled turnaround. Costs of approximately $2,571,000 associated with the turnaround are included in direct operating expenses (exclusive of depreciation and amortization).

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

Cost Classifications

Cost of product sold (exclusive of depreciation and amortization) includes cost of crude oil, other feedstocks, blendstocks, pet coke expense and freight and distribution expenses. Cost of product sold excludes depreciation and amortization of approximately $2,464,000, $2,390,000, and $2,148,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Direct operating expenses (exclusive of depreciation and amortization) includes direct costs of labor, maintenance and services, energy and utility costs, environmental compliance costs as well as chemicals and catalysts and other direct operating expenses. Direct operating expenses exclude depreciation and amortization

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of approximately $78,040,000, $57,367,000 and $47,714,000 for the years ended December 31, 2008, 2007 and 2006, respectively. Direct operating expenses also exclude depreciation of $7,627,000 for the year ended December 31, 2007 that is included in Net Costs Associated with Flood on the consolidated statement of operations as a result of the assets being idle due to the June/July 2007 flood.

Selling, general and administrative expenses (exclusive of depreciation and amortization) consist primarily of legal expenses, treasury, accounting, marketing, human resources and maintaining the corporate offices in Texas and Kansas. Selling, general and administrative expenses exclude depreciation and amortization of approximately $1,673,000, $1,022,000 and $1,142,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Income Taxes

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

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

Consolidation of Variable Interest Entities

In accordance with FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities*, (FIN 46R), management has reviewed the terms associated with its interests in the Partnership based upon the partnership agreement. Management has determined that the Partnership is a variable interest entity (VIE) and as such has evaluated the criteria under FIN 46R to determine that CVR is the primary beneficiary of the Partnership. FIN 46R requires the primary beneficiary of a variable interest entity s activities to consolidate the VIE. FIN 46R defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and where there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. As the primary beneficiary, CVR absorbs the majority of the expected losses and/or receives a majority of the expected residual returns of the VIE s activities.

The conclusion that CVR is the primary beneficiary of the Partnership and 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 CVR owns. 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.

Impairment of Long-Lived Assets

CVR accounts for long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. In accordance with SFAS 144, CVR reviews long-lived assets (excluding goodwill, intangible assets with indefinite lives, and deferred tax assets) for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated

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undiscounted future net cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future net cash flows, an impairment charge is recognized for the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of their carrying value or fair value less cost to sell. No impairment charges were recognized for any of the periods presented.

Revenue Recognition

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

Shipping Costs

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

Derivative Instruments and Fair Value of Financial Instruments

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

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

Share-Based Compensation

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

In accordance with SFAS 123(R), CVR, CALLC, CALLC II and CALLC III apply a fair-value based measurement method in accounting for share-based compensation. In accordance with EITF 00-12, CVR recognizes the costs of the share-based compensation incurred by CALLC, CALLC II and CALLC III on its behalf, primarily in selling, general, and administrative expenses (exclusive of depreciation and amortization), and a corresponding capital contribution, as the costs are incurred on its behalf, following the guidance in EITF Issue No. 96-18, *Accounting for Equity Investments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling Goods or Services*, which requires remeasurement at each reporting period through the performance commitment period, or in CVR s case, through the vesting period.

Non-vested shares, when granted, are valued at the closing market price of CVR s common stock on the date of issuance and amortized to compensation expense on a straight-line basis over the vesting period of the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stock. The fair value of the stock options is estimated on the date of grant using the Black Scholes option pricing model.

As of December 31, 2008, there had been 181,120 shares of non-vested common stock awarded. Although ownership of the shares does not transfer to the recipients until the shares have vested, recipients have voting and non-forfeitable dividend rights on these shares from the date of grant. See Note 3, Share-Based Compensation .

Environmental Matters

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

Use of Estimates

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

New Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price) . The standard s provisions for financial assets and financial liabilities, which became effective January 1, 2008, had no material impact on the Company s financial position or results of operations. At December 31, 2008, the only financial assets and liabilities that are measured at fair value on a recurring basis are the Company s derivative instruments.

In February 2008, the FASB issued FASB Staff Position 157-2 which defers the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in an entity s financial statements on a recurring basis (at least annually). As required, the Company adopted SFAS 157 as of January 1, 2009. Management believes the adoption of SFAS 157 deferral provisions will not have a material impact on the Company s financial position or earnings.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement defines the acquirer as the entity that obtains control of one or more businesses in the business combination, establishes the acquisition date as the date that the acquirer achieves control and requires the acquirer to recognize the assets acquired, liabilities assumed and any noncontrolling interest at their fair values as of the acquisition date. This statement also requires that acquisition-related costs of the acquirer be recognized separately from the business combination and will generally be expensed as incurred. As required, the Company adopted this statement as of January 1, 2009. The impact of adopting SFAS 141R will be limited to any future business combinations for which the acquisition date is on or after January 1, 2009.

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In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 must be applied prospectively. As required, the Company adopted this statement as of January 1, 2009. At the current time, the most significant impact of SFAS 160 on the Company s financial statements will be the classification of the noncontrolling interest on the Consolidated Balance Sheets as equity.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* This statement will change the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedge items affect an entity s financial position, net earnings, and cash flows. As required, the Company adopted this statement as of January 1, 2009. The Company currently discloses many of the quantitative and qualitative disclosures required by SFAS 161.

(3) Share-Based Compensation

Prior to CVR s initial public offering, CVR s subsidiaries were held and operated by CALLC, a limited liability company. Management of CVR holds an equity interest in CALLC. CALLC issued non-voting override units to certain management members who held common units of CALLC. There were no required capital contributions for the override operating units. In connection with CVR s initial public offering in October 2007, CALLC was split into two entities: CALLC and CALLC II. In connection with this split, management s equity interest in CALLC, including both their common units and non-voting override units, was split so that half of management s equity interest was in CALLC and half was in CALLC II. CALLC was historically the primary reporting company and CVR s predecessor. In addition, in connection with the transfer of the managing general partner of the Partnership to CALLC III in October 2007, CALLC III issued non-voting override units to certain management members of CALLC III.

At December 31, 2008, the value of the override units of CALLC and CALLC II 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 the Company s common stock price with a Black-Scholes option pricing formula, as remeasured at each reporting date until the awards are vested.

The estimated fair value of the override units of CALLC III has been determined using a probability-weighted expected return method which utilizes CALLC III s cash flow projections, which are representative of the nature of interests held by CALLC III in the Partnership.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides key information for the share-based compensation plans related to the override units of CALLC, CALLC II, and CALLC III. Compensation expense amounts are disclosed in thousands.

Award Type	Benchmark Value (per Unit)	Awards Issued	Grant Date	*Compensation Expense Increase (Decrease) for the Years December 31, 2008	2007	2006
Override Operating Units(a)	$ 11.31	919,630	June 2005	$ (5,979)	$ 10,675	$ 1,158
Override Operating Units(b)	$ 34.72	72,492	December 2006	(430)	877	3
Override Value Units(c)	$ 11.31	1,839,265	June 2005	(11,063)	12,788	677
Override Value Units(d)	$ 34.72	144,966	December 2006	(493)	718	17
Override Units(e)	$ 10.00	138,281	October 2007	(2)	2	
Override Units(f)	$ 10.00	642,219	February 2008	5		
			Total	$ (17,962)	$ 25,060	$ 1,855

* As CVR s common stock price increases or decreases, compensation expense increases or is reversed in correlation with the calculation of the fair value under the probability weighted expected return method.

Valuation Assumptions

(a) *Override Operating Units* In accordance with SFAS 123(R), using the Monte Carlo method of valuation, the estimated fair value of the override operating units on June 24, 2005 was $3,605,000. As discussed above, remeasurement occurs at each reporting period through the vesting period. Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Explicit service period	Based on forfeiture schedule in (b) below	Based on forfeiture schedule in (b) below
Grant date fair value	$5.16 per share	N/A
December 31, 2008 CVR closing stock price	N/A	$4.00
December 31, 2008 estimated fair value	N/A	$8.25 per unit
Marketability and minority interest discounts	24% discount	15% discount
Volatility	37%	68.8%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(b) *Override Operating Units* In accordance with SFAS 123(R), using a combination of a binomial model and a probability-weighted expected return method which utilized CVR s cash flow projections, the estimated fair value of the override operating units on December 28, 2006 was $473,000. As discussed above, remeasurement occurs at each reporting period through the vesting period. Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Explicit service period	Based on forfeiture schedule below	Based on forfeiture schedule below
Grant date fair value	$8.15 per share	N/A
December 31, 2008 CVR closing stock price	N/A	$4.00
December 31, 2008 estimated fair value	N/A	$1.59 per unit
Marketability and minority interest discounts	20% discount	15% discount
Volatility	41%	68.8%

On the tenth anniversary of the issuance of override operating units, such units convert into an equivalent number of override value units. Override operating units are forfeited upon termination of employment for cause. In the event of all other terminations of employment, the override operating units are initially subject to forfeiture as follows:

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

(c) *Override Value Units* In accordance with SFAS 123(R), using the Monte Carlo method of valuation, the estimated fair value of the override value units on June 24, 2005 was $4,065,000. As discussed above, remeasurement occurs at each reporting period through the vesting period. Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Derived service period	6 years	6 years
Grant date fair value	$2.91 per share	N/A
December 31, 2008 CVR closing stock price	N/A	$4.00
December 31, 2008 estimated fair value	N/A	$3.20 per unit
Marketability and minority interest discounts	24% discount	15% discount
Volatility	37%	68.8%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(d) *Override Value Units* In accordance with SFAS 123(R), using a combination of a binomial model and a probability-weighted expected return method which utilized CVR s cash flow projections, the estimated fair value of the override value units on December 28, 2006 was $945,000. As discussed above, remeasurement occurs at each reporting period through the vesting period. Significant assumptions used in the valuation were as follows:

	Grant Date	Remeasurement Date
Estimated forfeiture rate	None	None
Derived service period	6 years	6 years
Grant date fair value	$8.15 per share	N/A
December 31, 2008 CVR closing stock price	N/A	$4.00
December 31, 2008 estimated fair value	N/A	$1.59 per unit
Marketability and minority interest discounts	20% discount	15% discount
Volatility	41%	68.8%

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

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

(e) *Override Units* In accordance with SFAS 123(R), *Share-Based Compensation,* using a binomial and a probability-weighted expected return method which utilized CALLC III s cash flows projections which includes expected future earnings and the anticipated timing of IDRs, the estimated grant date fair value of the override units was approximately $3,000. In accordance with EITF 00-12, as a non-contributing investor, CVR also recognized income equal to the amount that its interest in the investee s net book value has increased (that is its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation cost. This amount equaled the compensation expense recognized for the awards for the years ended December 31, 2008 and 2007. As of December 31, 2008 these units were fully vested. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Grant date valuation	$0.02 per unit
Marketability and minority interest discount	15% discount

Volatility	34.7%

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(f) *Override Units* In accordance with SFAS 123(R), *Share-Based Compensation,* using a probability-weighted expected return method which utilized CALLC III s cash flows projections which includes expected future earnings and the anticipated timing of IDRs, the estimated grant date fair value of the override units was approximately $3,000. In accordance with EITF 00-12, as a non-contributing investor, CVR also recognized income equal to the amount that its interest in the investee s net book value has increased (that is its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation cost. This amount equaled the compensation expense recognized for the awards for the years ended December 31, 2008 and 2007. Of the 642,219 units issued, 109,720 were immediately vested upon issuance and the remaining units are subject to a forfeiture schedule. Significant assumptions used in the valuation were as follows:

Estimated forfeiture rate	None
Derived Service Period	Based on forfeiture schedule
December 31, 2008 estimated fair value	$0.02 per unit
Marketability and minority interest discount	20% discount
Volatility	64.3%

At December 31, 2008, assuming no change in the estimated fair value at December 31, 2008, there was approximately $3,362,000 of unrecognized compensation expense related to non-voting override units. This is expected to be recognized over a remaining period of approximately three years as follows (in thousands):

Year Ending December 31,	Override Operating Units	Override Value Units
2009	$ 619,000	$ 1,032,000
2010	186,000	1,033,000
2011		492,000
	$ 805,000	$ 2,557,000

Phantom Unit Appreciation Plan

CVR, through a wholly-owned subsidiary, has a Phantom Unit Appreciation Plan whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. Holders of service phantom points have rights to receive distributions when CALLC and CALLC II holders of override operating units receive distributions. Holders of performance phantom points have rights to receive distributions when CALLC and CALLC II holders of override value units receive distributions. There are no other rights or guarantees, and the plan expires on July 25, 2015 or at the discretion of the compensation committee of the board of directors. As of December 31, 2008, the issued Profits Interest (combined phantom points and override units) represented 15% of combined common unit interest and Profits Interest of CALLC and CALLC II. The Profits Interest was comprised of 11.1% and 3.9% of override interest and phantom interest, respectively. In accordance with SFAS 123(R), the expense associated with these awards for 2008 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 the Company s common stock price with a Black-Scholes option pricing formula, as remeasured at each reporting date until the awards are settled. Based upon this methodology, the service phantom interest and performance phantom interest were valued at $8.25 and $3.20 per point, respectively. CVR has recorded approximately $3,882,000 and $29,217,000 in personnel accruals as of December 31, 2008 and 2007, respectively. Compensation expense for the year ended December 31, 2008

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

related to the Phantom Unit Appreciation Plan was reversed by $25,335,000. Compensation expense for the year ended December 31, 2007 was $18,400,000.

At December 31, 2008, assuming no change in the estimated fair value at December 31, 2008, there was approximately $1,164,000 of unrecognized compensation expense related to the Phantom Unit Appreciation Plan. This is expected to be recognized over a remaining period of approximately three years.

Long Term Incentive Plan

The CVR Energy, Inc. 2007 Long Term Incentive Plan, or the LTIP, permits the grant of options, stock appreciation rights, or SARs, non-vested shares, non-vested share units, dividend equivalent rights, share awards and performance awards (including performance share units, performance units and performance-based restricted stock). Individuals who are eligible to receive awards and grants under the LTIP include the Company s subsidiaries employees, officers, consultants, advisors and directors. A summary of the principal features of the LTIP is provided below.

Shares Available for Issuance. The LTIP authorizes a share pool of 7,500,000 shares of the Company s common stock, 1,000,000 of which may be issued in respect of incentive stock options. Whenever any outstanding award granted under the LTIP expires, is canceled, is settled in cash or is otherwise terminated for any reason without having been exercised or payment having been made in respect of the entire award, the number of shares available for issuance under the LTIP shall be increased by the number of shares previously allocable to the expired, canceled, settled or otherwise terminated portion of the award. As of December 31, 2008, 7,286,530 shares of common stock were available for issuance under the LTIP.

Non-vested shares

A summary of the status of CVR s non-vested shares as of December 31, 2008 and changes during the year ended December 31, 2008 is presented below:

	Shares (In 000 s)	**Weighted Average Grant-Date Fair Value**
Non-vested at December 31, 2007	18	$ 20.88
Granted	164	4.14
Vested	(103)	5.09
Forfeited		
Non-vested at December 31, 2008	79	$ 6.62

As of December 31, 2008, there was approximately $395,000 of total unrecognized compensation cost related to non-vested shares to be recognized over a weighted-average period of approximately one year. The aggregate fair value at the grant date of the shares that vested during the year ended December 31, 2008 was $521,000. As of December 31, 2008, there were approximately 79,000 shares of unvested stock outstanding with an aggregate fair value at grant date of $521,000 compared to $365,000 at December 31, 2007. The aggregate intrinsic value of the non-vested shares at December 31, 2008, was approximately $315,000 compared to $436,000 at December 31, 2007. Total compensation expense recorded in 2008 and 2007 related to the non-vested stock was $606,000 and $42,000, respectively.

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Stock Options

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

	Shares (In 000 s)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term
Outstanding, December 31, 2007	19	$ 21.61	9.89
Granted	13	15.52	9.67
Exercised			
Forfeited			
Expired			
Outstanding, December 31, 2008	32	$ 19.08	9.21
Vested or expected to vest at December 31, 2008	6	21.61	8.89
Exercisable at December 31, 2008	6	21.61	8.89

The weighted average grant-date fair value of options granted during the years ended December 31, 2008 and 2007 was $8.97 and $12.47 per share, respectively. The aggregate intrinsic value of options exercisable at December 31, 2008, was $0, as all of the exercisable options were out-of-the-money. Total compensation expense recorded in 2008 and 2007 related to the stock options was $166,000 and $15,000, respectively.

(4) Inventories

Inventories consisted of the following (in thousands):

	December 31, 2008	December 31, 2007
Finished goods	$ 61,008	$ 109,394
Raw materials and catalysts	45,928	92,104
In-process inventories	14,376	29,817
Parts and supplies	27,112	23,340
	$ 148,424	$ 254,655

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) Property, Plant, and Equipment

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

	December 31, 2008	December 31, 2007
Land and improvements	$ 17,383	$ 13,058
Buildings	22,851	17,541
Machinery and equipment	1,288,782	1,108,858
Automotive equipment	7,825	5,171
Furniture and fixtures	7,835	6,304
Leasehold improvements	1,081	929
Construction in progress	53,927	182,046
	1,399,684	1,333,907
Accumulated depreciation	220,719	141,733
	$ 1,178,965	$ 1,192,174

Capitalized interest recognized as a reduction in interest expense for the years ended December 31, 2008, 2007 and 2006 totaled approximately $2,370,000, $12,049,000 and $11,613,000, respectively. Land and building that are under a capital lease obligation approximated $4,827,000 as of December 31, 2008. Amortization of assets held under capital leases is included in depreciation expense.

(6) Goodwill and Intangible Assets

Goodwill

In connection with the 2005 acquisition by CALLC of all outstanding stock owned by Coffeyville Holding Group, LLC, CALLC recorded goodwill of $83,775,000. SFAS No. 142, *Goodwill and Other Intangible Assets*, provides that goodwill and other intangible assets with indefinite lives shall not be amortized but shall be tested for impairment on an annual basis. In accordance with SFAS 142, CVR completed its annual test for impairment of goodwill as of November 1, 2008. For 2008, the estimated fair values indicated the second step of goodwill impairment analysis was required for the petroleum segment, but not for the fertilizer segment. The analysis under the second step showed that the current carrying value of goodwill could not be sustained for the petroleum segment. Accordingly, the Company recorded a non-cash goodwill impairment charge of $42,806,000 related to the petroleum segment in 2008.

The annual assessment considered future discounted cash flow projections, assumptions about market participant views, and the Company s overall market capitalization around the testing period. All of the factors worsened during the fourth quarter of 2008 compared to amounts used for 2007 evaluations. Deteriorating market conditions in the fourth quarter of 2008 in the Company s petroleum segment, including significant declines in crude oil and refining margins, caused significant downward changes in forecasted earnings. These forecasted margins and earnings are volatile and are impacted by market forces beyond the Company s control; as such the forecast may not be indicative of actual results. The circumstances impacting forecasted margins and earnings included current and projected market conditions surrounding demand. The decline in the projected demand was the result of the overall downturn in the economy and the perception that the economy would be in a recession for the foreseeable future. These overall deteriorating conditions resulted in a significant decline in the estimated fair market value of the petroleum segment and full write-off of the related goodwill in the fourth quarter of 2008.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The annual review of impairment was performed by comparing the carrying value of the applicable reporting unit to its estimated fair value. The valuation analysis used in the analysis utilized a 50% weighting of both income and market approaches as described below:

Income Approach: To determine fair value, the Company discounted the expected future cash flows for each reporting unit utilizing observable market data to the extent available. The discount rates used range from 18.3% to 22.8% representing the estimated weighted average costs of capital, which reflects the overall level of inherent risk involved in each reporting unit and the rate of return an outside investor would expect to earn.

Market-Based Approach: To determine the fair value of each reporting unit, the Company also utilized a market based approach. The Company used the guideline company method, which focuses on comparing the Company s risk profile and growth prospects to select reasonably similar/guideline publicly traded companies.

The approach the Company used to review its annual impairment of goodwill in 2007 also utilized both the income and market based approaches.

As of the result of the potential impairment as indicated by Step 1 for the Petroleum reporting unit, the Company completed the second step of the impairment test. In Step 2, the fair values of each of the reporting unit s identifiable assets and liabilities are determined as they would be in a business combination accounted for under purchase accounting, and the excess of the deemed purchase price over the net fair value of all of the identifiable assets and liabilities represents the implied fair value of the goodwill of that reporting unit. If the carrying amount of that reporting unit s goodwill exceeds this implied fair value of goodwill, an impairment loss is recognized in the amount of that excess to reduce the carrying amount of goodwill to the implied fair value determined in the hypothetical purchase price allocation. As a result of carrying out Step 2, the Company determined the carrying value of goodwill assigned to the Petroleum reporting unit exceeded the implied fair value of the goodwill, and thus recorded a full impairment charge of $42,806,000.

In connection with the goodwill impairment analysis performed by the Company, a review of long-lived assets was conducted as required by SFAS No. 144, *Accounting for the Impairment of Long-Lived Assets*. Based upon the estimated undiscounted cash flows, the carrying value of the Company s long-lived assets is supported and, therefore, no impairment was recognized.

Other Intangible Assets

Contractual agreements with a fair market value of $1,322,000 were acquired in 2005 in connection with the acquisition by CALLC of all outstanding stock owned by Coffeyville Holding Group, LLC. The intangible value of these agreements is amortized over the life of the agreements through June 2025. Amortization expense of $64,000, $165,000, and $370,000 was recorded in depreciation and amortization for the years ended December 31, 2008, 2007 and 2006, respectively.

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

Year Ending December 31,	Contractual Agreements
2009	33
2010	33
2011	33
2012	28
2013	27
Thereafter	256
	410

(7) Deferred Financing Costs

On December 22, 2008, CRLLC entered into a second amendment to its outstanding credit facility. In connection with this amendment, the Company paid approximately $8,522,000 of lender and third party costs. This amendment was within the scope of the EITF 96-19, *Debtor s Accounting for Modification or Exchange of Debt Instruments*, as well as EITF 98-14, *Debtor s Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*. In accordance with that guidance the Company recorded a loss on the extinguishment of debt of $4,681,000 associated with the lender fees incurred on the term debt and also recorded an additional loss on a portion of the unamortized loan costs of $5,297,000 previously deferred at the time of the original credit facility, which was entered into on December 28, 2006. Total loss on extinguishment of debt recorded was $9,978,000. The remaining costs incurred of $3,841,000 were deferred and will be amortized as interest expense using the effective-interest amortization method for the term debt and the straight-line method for the letter of credit facility and revolving credit facility.

Deferred financing costs of $2,088,000 were paid in conjunction with three new credit facilities entered into August 2007 as a result of the June/July 2007 flood and crude oil discharge. The unamortized amount of these deferred financing costs of $1,258,000 were written off when the related debt was extinguished upon the consummation of the initial public offering and these costs were included in loss on extinguishment of debt for the year ended December 31, 2007. Amortization of deferred financing costs reported as interest expense and other financing costs was $831,000 using the effective-interest amortization method.

Deferred financing costs of $24,628,000 were paid in connection with the acquisition by CALLC of all outstanding stock owned by Coffeyville Group Holdings, LLC. Effective December 28, 2006, the Company amended and restated its credit agreement with a consortium of banks, additionally capitalizing $8,462,000 in debt issuance costs. This amendment and restatement was within the scope of the EITF 96-19, *Debtor s Accounting for Modification or Exchange of Debt Instruments*, as well as EITF 98-14, *Debtor s Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*. In accordance with that guidance, a portion of the unamortized loan costs of $16,959,000 from the original credit facility as well as additional finance and legal charges associated with the second amended and restated credit facility of $901,291 were included in loss on extinguishment of debt for the year

December 31, 2006. The remaining costs are being amortized over the life of the related debt instrument. Additionally, a prepayment penalty of $5,500,000 on the previous credit facility was also paid and expensed and included in loss on extinguishment of debt for the year ended December 31, 2006.

For the years ended December 31, 2008, 2007 and 2006, amortization of deferred financing costs reported as interest expense and other financing costs totaled $1,991,000, $1,947,000, and $3,337,000, respectively, using the effective-interest amortization method for the term debt and the straight-line method for the letter of credit facility and revolving loan facility.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2008	December 31, 2007
Deferred financing costs	$ 8,045	$ 12,278
Less accumulated amortization	1,991	2,778
Unamortized deferred financing costs	6,054	9,500
Less current portion	2,171	1,985
	$ 3,883	$ 7,515

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

Year Ending December 31,	Deferred Financing
2009	$ 2,171
2010	2,158
2011	804
2012	800
2013	121
	$ 6,054

(8) Note Payable and Capital Lease Obligations

The Company entered into an insurance premium finance agreement with Cananwill, Inc. in July 2008 and July 2007 to finance the purchase of its property, liability, cargo and terrorism policies. The original balances of these notes were $10,000,000 and $7,646,000 for 2008 and 2007, respectively. Both notes were to be repaid in equal installments with the final payment due for the 2008 note in June 2009. As of December 31, 2008 and December 31, 2007 the Company owed $7,500,000 and $3,398,000 related to these notes. The balance due for the July 2007 note was paid in full in April 2008.

The Company entered into two capital leases in 2007 to lease platinum required in the manufacturing of new catalyst. The leases terminate on the date an equal amount of platinum is returned to each lessor, with the difference to be paid in cash. Both leases were settled in 2008 with the return of platinum and cash payments totaling approximately $1,455,000. At December 31, 2007 the lease obligations were recorded at $8,242,000 on the Consolidated Balance Sheets.

The Company also entered into a capital lease for real property used for corporate purposes on May 29, 2008. The lease has an initial lease term of one year with an option to renew for three additional one-year periods. The Company has the option to purchase the property during the initial lease term or during the renewal periods if the lease is renewed. In connection with the capital lease the Company recorded a capital asset and capital lease obligation of $4,827,000. The capital lease obligation was $4,043,000 as of December 31, 2008.

(9) Flood

On June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville, Kansas. As a result, the Company s refinery and nitrogen fertilizer plant were severely flooded, resulting in repairs and maintenance needed for the refinery assets. The nitrogen fertilizer facility also sustained damage, but to a much lesser degree. The Company maintained property

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

damage insurance which included damage caused by a flood, up to $300,000,000 per occurrence, subject to deductibles and other limitations. The deductible associated with the property damage was $2,500,000.

Additionally, crude oil was discharged from the Company s refinery on July 1, 2007 due to the short amount of time to shut down and save the refinery in preparation of the June/July 2007 flood that occurred on June 30, 2007. The Company maintained insurance policies related to environmental cleanup costs and potential liability to third parties for bodily injury or property damage. The policies were subject to a $1,000,000 self-insured retention.

As of December 31, 2008, the Company has recorded total gross costs associated with the repair of and other matters relating to the damage to the Company s facilities and with third party and property damage claims incurred due to the crude oil discharge of approximately $156,327,000. Total anticipated insurance recoveries of approximately $106,941,000 from all associated policies including property insurance, environmental and builders risk have been recorded as of December 31, 2008 (of which $94,185,000 had already been received as of December 31, 2008 by the Company from insurance carriers). At December 31, 2008, total accounts receivable from insurance was $12,756,000. The receivable balance is segregated between current and long-term in the Company s Consolidated Balance Sheet in relation to the nature and classification of the items to be settled. As of December 31, 2008, $1,000,000 of the amounts receivable from insurers was not anticipated to be collected in the next twelve months, and therefore has been classified as a non-current asset. Management believes the recovery of the receivable from the insurance carriers is probable.

Additional insurance proceeds were received under the Company s property insurance policy and builders risk policy subsequent to December 31, 2008, in the amount of $11,756,000. All property insurance claims and builders risk claims have now been fully settled with all claims closed.

The Company has recorded net pretax costs in total since the occurrence of the June/July 2007 flood of approximately $49,386,000 associated with both the June/July 2007 flood and related crude oil discharge. This amount is net of anticipated insurance recoveries of $106,941,000.

Below is a summary of the reconciliation of the insurance receivable (in thousands):

	Receivable Reconciliation
Total insurance receivable	$ 106,941
Less insurance proceeds received through December 31, 2008	(94,185)
Insurance receivable	$ 12,756

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(10) Income Taxes

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

	Year Ended December 31,		
	2008	2007	2006
Current			
Federal	$ 8,474	$ (26,814)	$ 26,096
State	(409)	(4,017)	6,974
Total current	8,065	(30,831)	33,070
Deferred			
Federal	57,236	(21,434)	69,836
State	(1,390)	(36,250)	16,934
Total deferred	55,846	(57,684)	86,770
Total income tax expense (benefit)	$ 63,911	$ (88,515)	$ 119,840

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

	Year Ended December 31,		
	2008	2007	2006
Tax computed at federal statutory rate	$ 79,746	$ (54,720)	$ 108,994
State income taxes, net of federal tax benefit (expense)	13,372	(6,382)	15,618
State tax incentives, net of federal tax expense	(14,519)	(19,792)	(78)
Manufacturing activities deduction	(913)		(1,089)
Federal tax credit for production of ultra-low sulfur diesel fuel	(23,742)	(17,259)	(4,462)
Non-deductible share-based compensation	(6,286)	8,771	649
Non-deductible goodwill impairment	14,982		
Other, net	1,271	867	208
Total income tax expense (benefit)	$ 63,911	$ (88,515)	$ 119,840

Certain provisions of the American Jobs Creation Act of 2004 (the Act) are providing federal income tax benefits to CVR. The Act created Internal Revenue Code section 199 which provides an income tax benefit to domestic manufacturers. CVR recognized an income tax benefit related to this manufacturing deduction of approximately $913,000, $0 and $1,089,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

The Act also provides for a $0.05 per gallon income tax credit on compliant diesel fuel produced up to an amount equal to the remaining 25% of the qualified capital costs. CVR recognized an income tax benefit of approximately $23,742,000, $17,259,000 and $4,462,000 on a credit of approximately $36,526,000, $26,552,000, and $6,865,000 related to the production of ultra low sulfur diesel for the years ended December 31, 2008, 2007 and 2006, respectively.

The Company earns Kansas High Performance Incentive Program (HPIP) credits for qualified business facility investment within the state of Kansas. CVR recognized a net income tax benefit of approximately $14,519,000, $19,792,000 and $78,000 on a credit of approximately $22,337,000, $30,449,000 and $120,000 for the years ended December 31, 2008, 2007 and 2006.

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The income tax effect of temporary differences that give rise to significant portions of the deferred income tax assets and deferred income tax liabilities at December 31, 2008 and 2007 are as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In thousands)	
Deferred income tax assets:		
Allowance for doubtful accounts	$ 1,638	$ 156
Personnel accruals	2,564	12,757
Inventories	426	671
Unrealized derivative losses, net		85,650
Low sulfur diesel fuel credit carry forward	50,263	17,860
State net operating loss carry forwards, net of federal expense	854	4,158
Accrued expenses	234	1,713
Deferred revenue		3,403
State tax credit carryforward, net of federal expense	31,994	17,475
Deferred financing	3,388	
Net costs associated with flood	2,276	1,351
Other	256	
Total Gross deferred income tax assets	93,893	145,194
Deferred income tax liabilities:		
Property, plant, and equipment	(340,292)	(348,901)
Prepaid expenses	(4,247)	(3,233)
Deferred financing		(513)
Unrealized derivative gains, net	(13,139)	
Other		(486)
Total Gross deferred income tax liabilities	(357,678)	(353,133)
Net deferred income tax liabilities	$ (263,785)	$ (207,939)

At December 31, 2008, CVR has net operating loss carryforwards for state income tax purposes of approximately $1,313,000, which are available to offset future state taxable income. The net operating loss carryforwards, if not utilized, will expire between 2012 and 2027.

At December 31, 2008, CVR has federal tax credit carryforwards related to the production of low sulfur diesel fuel of approximately $50,263,000, which are available to reduce future federal regular income taxes. These credits, if not used, will expire in 2027 and 2028. CVR also has Kansas state income tax credits of approximately $49,221,000, which are available to reduce future Kansas state regular income taxes. These credits, if not used, will expire in 2017 and 2018.

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

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likely than not that all of the deferred tax assets will be realized and thus, no valuation allowance was provided as of December 31, 2008 and 2007.

CVR adopted FIN 48 effective January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the financial statements. If the probability of sustaining a tax position is at least more likely than not, then the tax position is warranted and recognition should be at the highest amount which is greater than 50% likely of being realized upon ultimate settlement. As of the date of adoption of FIN 48 and at December 31, 2008, CVR did not believe it had any tax positions that met the criteria for uncertain tax positions. As a result, no amounts were recognized as a liability for uncertain tax positions.

CVR recognizes interest and penalties on uncertain tax positions and income tax deficiencies in income tax expense. CVR did not recognize any interest or penalties in 2008 or 2007 for uncertain tax positions or income tax deficiencies. Certain subsidiaries of the Company closed an examination with the United States Internal Revenue Service of their 2005 federal income tax return with no adjustments. At December 31, 2008, the Company is generally open to examination in the United States and various individual states for the tax years ended December 31, 2005 through December 31, 2008.

A reconciliation of the unrecognized tax benefits for the year ended December 31, 2008, is as follows:

Balance as of January 1, 2008	$ 0
Increase and decrease in prior year tax positions	
Increases and decrease in current year tax positions	
Settlements	
Reductions related to expirations of statute of limitations	
Balance as of December 31, 2008	$ 0

(11) Long-Term Debt

On December 28, 2006, CRLLC entered into a credit facility with a consortium of banks and one related party institutional lender (see Note 17). The credit facility was in an aggregate amount of $1,075,000,000, consisting of $775,000,000 of tranche D term loans; a $150,000,000 revolving credit facility; and a funded letter of credit facility of $150,000,000. The credit facility was secured by substantially all of CRLLC s and its subsidiaries assets. At December 31, 2008 and December 31, 2007, $484,328,000 and $489,202,000, respectively, of tranche D term loans were outstanding, and there was no outstanding balance on the revolving credit facility. At December 31, 2008, and December 31, 2007, CRLLC had $150,000,000 in funded letters of credit outstanding to secure payment obligations under derivative financial instruments (see Note 16).

On December 22, 2008, CRLLC entered into a second amendment to its outstanding credit facility. The second amendment was entered into, among other things, to amend the definition of consolidated adjusted EBITDA to add a FIFO adjustment which applies for the year ending December 31, 2008 through the quarter ending September 30, 2009. This FIFO adjustment will be used for the purpose of testing compliance with the financial covenants under the credit facility until the quarter ending June 30, 2010. As part of the amendment, CRLLC s interest rate margin increased by 2.50% and LIBOR and the base rate have been set at a minimum of 3.25% and 4.25%, respectively.

At December 31, 2008, the term loan and revolving credit facility provide CRLLC the option of a 3-month LIBOR rate plus 5.25% per annum (rounded up to the next whole multiple of 1/16 of 1%) or a base rate (to be based on the current prime rate or federal funds rate plus 4.25%). Interest is paid quarterly when using the base rate and at the expiration of the LIBOR term selected when using the LIBOR rate; interest varies with the base rate or LIBOR rate in effect at the time of the borrowing. At December 31, 2007 the term loan and revolving credit facility provided CRLLC the option of a 3-month LIBOR rate plus 2.75% per annum

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(rounded up to the next whole multiple of 1/16 of 1%) or a base rate (to be based on the current prime rate or federal funds rate plus 1.75%). The interest rate on December 31, 2008 and December 31, 2007 was 9.13% and 7.98%, respectively. The annual fee for the funded letter of credit facility was 5.475% and 2.975%, at December 31, 2008 and 2007, respectively.

Under the terms of our credit facility, the interest margin paid is subject to change based on changes in our leverage ratio and changes in our credit rating by either S&P or Moody s. S&P s recent announcement in February 2009 to place the Company on negative outlook resulted in an increase in our interest rate of 0.25% on amounts borrowed under our term loan facility, revolving credit facility and the $150,000,000 funded letter of credit facility.

Our credit facility contains customary restrictive covenants applicable to CRLLC, including limitations on the level of additional indebtedness, commodity agreements, capital expenditures, payment of dividends, creation of liens, and sale of assets. These covenants also require CRLLC to maintain specified financial ratios as follows:

First Lien Credit Facility

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

Failure to comply with the various restrictive and affirmative covenants in the credit facility could negatively affect CRLLC s ability to incur additional indebtedness. CRLLC is required to measure its compliance with these financial ratios and covenants quarterly and was in compliance with all covenants and reporting requirements under the terms of the agreement as amended on December 22, 2008. As required by the credit facility, CRLLC has entered into interest rate swap agreements that are required to be held for the remainder of the stated term.

Long-term debt at December 31, 2008 consisted of the following future maturities:

	Year Ending December 31,	**Amount**
First lien Tranche D term loans; principal payments	2009	$ 4,825,000
of .25% of the principal balance due quarterly	2010	4,777,000
increasing to 23.5% of the principal balance due	2011	4,730,000
quarterly commencing April 2013, with a final	2012	4,682,000
payment of the aggregate remaining unpaid principal	2013	465,314,000
balance due December 2013	Thereafter	
		$ 484,328,000

Commencing with fiscal year 2007, CRLLC shall prepay the loans in an aggregate amount equal to 100% of consolidated excess cash flow, which is defined in the credit facility and includes a formulaic calculation consisting of many financial statement items, starting with consolidated adjusted EBITDA) less 100% of voluntary prepayments made during that fiscal year. Commencing with fiscal year 2008, the aggregate amount changed to 75% of consolidated excess cash flow provided the total leverage ratio is less than 1:50:1:00 or 50% of consolidated excess cash flow provided the total leverage ratio is less than 1:00:1:00.

At December 31, 2008, CRLLC had $3,349,000 in letters of credit outstanding to collateralize its environmental obligations and $46,569,000 in letters of credit outstanding to secure transportation services for crude oil. These letters of credit were outstanding under the revolving credit facility. The fee for the revolving letters of credit is 5.50%.

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The revolving credit facility has a current expiration date of December 28, 2012. The funded letter of credit facility has a current expiration date of December 28, 2010.

As a result of the June/July 2007 flood and crude oil discharge, the Company s subsidiaries entered into three new credit facilities in August 2007. CRLLC entered into a $25,000,000 senior secured credit facility. CRLLC also entered into a $25,000,000 senior unsecured credit facility. Coffeyville Refining & Marketing Holdings, Inc., entered into a $75,000,000 million senior unsecured credit facility. All indebtedness outstanding under the $25,000,000 secured facility and the $25,000,000 unsecured facility was repaid in October 2007 with the proceeds of the Company s initial public offering, and all three facilities were terminated at that time.

(12) Earnings Per Share

On October 26, 2007, the Company completed the initial public offering of 23,000,000 shares of its common stock. Also, in connection with the initial public offering, a reorganization of entities under common control was consummated whereby the Company became the indirect owner of the subsidiaries of CALLC and CALLC II and all of their refinery and fertilizer assets. This reorganization was accomplished by the Company issuing 62,866,720 shares of its common stock to CALLC and CALLC II, its majority stockholders, in conjunction with a 628,667.20 for 1 stock split and the merger of two newly formed direct subsidiaries of CVR. Immediately following the completion of the offering, there were 86,141,291 shares of common stock outstanding, excluding non-vested shares issued. See Note 1, Organization and History of the Company and Basis of Presentation .

2008 Earnings Per Share

	For the Year Ended December 31, 2008 (In thousands except share data)	
Net income	$	163,935
Average number of shares of common stock outstanding		86,145,543
Effect of dilutive securities:		
The computations of the basic and diluted earnings per share for the year ended December 31, 2008 is as follows:		
Non-vested common stock		78,666
Average number of shares of common stock outstanding assuming dilution		86,224,209
Basic earnings per share	$	1.90
Diluted earnings per share	$	1.90

Outstanding stock options totaling 32,350 common shares were excluded from the diluted earnings per share calculation for the year ended December 31, 2008 as they were antidilutive.

2007 and 2006 Pro Forma Earnings (Loss) Per Share

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

Pro forma earnings (loss) per share for the year ended December 31, 2007 and 2006 are calculated as noted below. For the year ended December 31, 2007, 17,500 non-vested common shares and 18,900 of common stock options have been excluded from the calculation of pro forma diluted earnings per share

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

because the inclusion of such common stock equivalents in the number of weighted average shares outstanding would be anti-dilutive:

	For the Year Ended December 31, 2007		For the Year Ended December 31, 2006	
	(Unaudited) (In thousands)			
Net income (loss)	$	(67,618)	$	191,571
Pro forma weighted average shares outstanding:				
Original CVR shares of common stock		100		100
Effect of 628,667.20 to 1 stock split		62,866,620		62,866,620
Issuance of shares of common stock to management in exchange for subsidiary shares		247,471		247,471
Issuance of shares of common stock to employees		27,100		27,100
Issuance of shares of common stock in the initial public offering		23,000,000		23,000,000
Basic weighted average shares outstanding		86,141,291		86,141,291
Dilutive securities issuance of non-vested shares of common stock to board of directors				17,500
Diluted weighted average shares outstanding		86,141,291		86,158,791
Pro forma basic earnings (loss) per share	$	(0.78)	$	2.22
Pro forma dilutive earnings (loss) per share	$	(0.78)	$	2.22

(13) Benefit Plans

CVR sponsors two defined-contribution 401(k) plans (the Plans) for all employees. Participants in the Plans may elect to contribute up to 50% of their annual salaries, and up to 100% of their annual income sharing. CVR matches up to 75% of the first 6% of the participant s contribution for the nonunion plan and 50% of the first 6% of the participant s contribution for the union plan. Both plans are administered by CVR and contributions for the union plan are determined in accordance with provisions of negotiated labor contracts. Participants in both Plans are immediately vested in their individual contributions. Both Plans have a three year vesting schedule for CVR s matching funds and contain a provision to count service with any predecessor organization. CVR s contributions under the Plans were $1,588,000, $1,513,000, and $1,375,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(14) Commitments and Contingent Liabilities

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

Year Ending December 31,	Operating Leases	Unconditional Purchase Obligations
2009	$ 4,040,000	$ 29,405,000
2010	2,704,000	35,939,000
2011	1,297,000	57,301,000
2012	903,000	54,584,000
2013	1,000	54,472,000
Thereafter		360,630,000
	$ 8,945,000	$ 592,331,000

CVR leases various equipment, including rail cars, and real properties under long-term operating leases expiring at various dates. For the years ended December 31, 2008, 2007 and 2006, lease expense totaled approximately $4,314,000, $3,854,000, and $3,822,000, respectively. The lease agreements have various remaining terms. Some agreements are renewable, at CVR s option, for additional periods. It is expected, in the ordinary course of business, that leases will be renewed or replaced as they expire.

CVR licenses a gasification process from a third party associated with gasifier equipment used in the Nitrogen Fertilizer segment. The royalty fees for this license were incurred as the equipment was used and were subject to a cap which was paid in full in 2007. Royalty fee expense reflected in direct operating expenses (exclusive of depreciation and amortization) for the years ended December 31, 2007 and 2006 was $1,035,000 and $2,135,000, respectively.

CRNF has an agreement with the City of Coffeyville (the City) pursuant to which it must make a series of future payments for electrical generation transmission and City margin based upon agreed upon rates. As of December 31, 2008, the remaining obligations of CRNF totaled $17,900,000 through July 1, 2019. Total minimum annual committed contractual payments under the agreement will be $1,705,000. The City, however, recently began charging a higher rate for electricity than what had been agreed to in the contract. The Company filed a lawsuit to have the contract enforced as written and to recover other damages. The Company has paid the higher rates in order to obtain the electricity. The Company believes it is probable that these amounts paid in excess of the rates agreed to in the contract are probable of recovery under the lawsuit. The Company believes that if the City is successful in the lawsuit, the higher electricity costs that it would be allowed to charge would not be material to the Company s results of operations.

CRRM has a Pipeline Construction, Operation and Transportation Commitment Agreement with Plains Pipeline, L.P. (Plains Pipeline) pursuant to which Plains Pipeline constructed a crude oil pipeline from Cushing, Oklahoma to Caney, Kansas. The term of the agreement is 20 years from when the pipeline became operational on March 1, 2005. Pursuant to the agreement, CRRM must transport approximately 80,000 barrels per day of its crude oil requirements for the Coffeyville refinery at a fixed charge per barrel for the first five years of the agreement. For the final fifteen years of the agreement, CRRM must transport all of its non-gathered crude oil up to the capacity of the Plains Pipeline. The rate is subject to a Federal Energy Regulatory Commission (FERC) tariff and is subject to change on an annual basis per the agreement. Lease expense associated with this agreement and included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2008, 2007 and 2006 totaled approximately $10,397,000, $7,214,000 and $8,751,000, respectively.

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2005, CRRM entered into a Pipeage Contract with MAPL pursuant to which CRRM agreed to ship a minimum quantity of NGLs on an inbound pipeline operated by MAPL between Conway, Kansas and Coffeyville, Kansas. Pursuant to the contract, CRRM is obligated to ship 2,000,000 barrels (Minimum Commitment) of NGLs per year at a fixed rate per barrel through the expiration of the contract on September 30, 2011. All barrels above the Minimum Commitment are at a different fixed rate per barrel. The rates are subject to a tariff approved by the Kansas Corporation Commission (KCC) and are subject to change throughout the term of this contract as ordered by the KCC. Lease expense associated with this contract agreement and included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2008, 2007 and 2006, totaled approximately $2,310,000, $1,400,000, and $1,613,000, respectively.

During 2004, CRRM entered into a Transportation Services Agreement with CCPS Transportation, LLC (CCPS) pursuant to which CCPS reconfigured an existing pipeline (Spearhead Pipeline) to transport Canadian sourced crude oil to Cushing, Oklahoma. The term of the agreement is 10 years from the time the pipeline becomes operational, which occurred March 1, 2006. Pursuant to the agreement and pursuant to options for increased capacity which CRRM has exercised, CRRM is obligated to pay an incentive tariff, which is a fixed rate per barrel for a minimum of 10,000 barrels per day. Lease expense associated with this agreement included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2008, 2007 and 2006 totaled approximately $8,428,000, $6,980,000 and $4,604,000, respectively.

During 2004, CRRM entered into a Terminalling Agreement with Plains Marketing, LP (Plains) whereby CRRM has the exclusive storage rights for working storage, blending, and terminalling services at several Plains tanks in Cushing, Oklahoma. During 2007, CRRM entered into an Amended and Restated Terminalling Agreement with Plains that replaced the 2004 agreement. Pursuant to the Amended and Restated Terminalling Agreement, CRRM is obligated to pay fees on a minimum throughput volume commitment of 29,200,000 barrels per year. Fees are subject to change annually based on changes in the Consumer Price Index (CPI-U) and the Producer Price Index (PPI-NG). Expenses associated with this agreement, included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2008, 2007 and 2006, totaled approximately $2,529,000, $2,396,000, and $2,406,000, respectively. The original term of the Amended and Restated Terminalling Agreement expires December 31, 2014, but is subject to annual automatic extensions of one year beginning two years and one day following the effective date of the agreement, and successively every year thereafter unless either party elects not to extend the agreement. Concurrently with the above-described Amended and Restated Terminalling Agreement, CRRM entered into a separate Terminalling Agreement with Plains whereby CRRM has obtained additional exclusive storage rights for working storage and terminalling services at several Plains tanks in Cushing, Oklahoma. CRRM is obligated to pay Plains fees based on the storage capacity of the tanks involved, and such fees are subject to change annually based on changes in the Producer Price Index (PPI-FG and PPI-NG). The term of the Terminalling Agreement is split up into two periods based on the tanks at issue, with the term for half of the tanks commencing once they are placed in service, and the term for the remaining half of the tanks commencing October 1, 2008. Expenses associated with this agreement totaled approximately $1,118,000 for the tanks in service between January 1, 2008 and September 30, 2008 and $745,000 for the tanks in service between October 1, 2008 and December 31, 2008. For the year ended December 31, 2008, expenses associated with this agreement totaled $1,863,000. Select tanks covered by this agreement have been designated as delivery points for crude oil. The original term of the Terminalling Agreement for both sets of tanks expires December 31, 2014, but is subject to annual automatic extensions of one year beginning two years and one day following the effective date of the agreement, and successively every year thereafter unless either party elects not to extend the agreement.

During 2005 CRNF entered into the Amended and Restated On-Site Product Supply Agreement with Linde, Inc. Pursuant to the agreement, which expires in 2020, CRNF is required to take as available and pay

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approximately $300,000 per month, which amount is subject to annual inflation adjustments, for the supply of oxygen and nitrogen to the fertilizer operation. Expenses associated with this agreement, included in direct operating expenses (exclusive of depreciation and amortization) for the years ended December 31, 2008, 2007 and 2006, totaled approximately $3,928,000, $3,449,000 and $3,521,000, respectively.

During 2006, CRRM entered into a Lease Storage Agreement with TEPPCO Crude Pipeline, L.P. (TEPPCO) whereby CRRM leases tank capacity at TEPPCO s Cushing tank farm in Cushing, Oklahoma. In September 2006, CRRM exercised its option to increase the shell capacity leased at the facility subject to this agreement. Pursuant to the agreement, CRRM is obligated to pay a monthly per barrel fee regardless of the number of barrels of crude oil actually stored at the leased facilities. Expenses associated with this agreement included in cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2008 and 2007 totaled approximately $1,320,000 and $1,110,000, respectively.

During 2007, CRRM executed a Petroleum Transportation Service Agreement with TransCanada Keystone Pipeline, LP (TransCanada). TransCanada is proposing to construct, own and operate a pipeline system and a related extension and expansion of the capacity that would terminate near Cushing, Oklahoma. TransCanada has agreed to transport a contracted volume amount of at least 25,000 barrels per day with a Cushing Delivery Point as the contract point of delivery. The contract term is a 10 year period which will commence upon the completion of the pipeline system. The expected date of commencement is the first quarter of 2011 with termination of the transportation agreement estimated to be 2021. The Company will pay a fixed and variable toll rate beginning during the month of commencement.

On October 10, 2008, the Company, through its wholly-owned subsidiaries entered into ten year agreements with Magellan Pipeline Company LP (Magellan) that will allow for the transportation of an additional 20,000 barrels per day of refined fuels from the Company s Coffeyville, Kansas refinery and the storage of refined fuels on the Magellan system.

CRNF entered into a sales agreement with Cominco Fertilizer Partnership on November 20, 2007 to purchase equipment and materials which comprise a nitric acid plant. CRNF s obligation related to the execution of the agreement in 2007 for the purchase of the assets was $3,500,000. As of December 31, 2008, $1,000,000 had been paid with $2,500,000 remaining as an accrued current obligation. Additionally, $2,874,000 was accrued related to the obligation to dismantle the unit. These amounts incurred are included in construction-in-progress at December 31, 2008. The total unpaid obligation at December 31, 2008 of $5,374,000 is included in other current liabilities on the Consolidated Balance Sheet.

From time to time, CVR is involved in various lawsuits arising in the normal course of business, including matters such as those described below under, Environmental, Health, and Safety Matters. Liabilities related to such litigation are recognized when the related costs are probable and can be reasonably estimated. Management believes the company has accrued for losses for which it may ultimately be responsible. It is possible that management s estimates of the outcomes will change within the next year due to uncertainties inherent in litigation and settlement negotiations. In the opinion of management, the ultimate resolution of any other litigation matters is not expected to have a material adverse effect on the accompanying consolidated financial statements. There can be no assurance that managements beliefs or opinions with respect to liability for potential litigation matters are accurate.

Crude oil was discharged from the Company s refinery on July 1, 2007 due to the short amount of time available to shut down and secure the refinery in preparation for the flood that occurred on June 30, 2007. In connection with the discharge, the Company received in May, 2008, notices of claims from sixteen private claimants under the Oil Pollution Act in an aggregate amount of approximately $4,393,000. In August, 2008, those claimants filed suit against the Company in the United States District Court for the District of Kansas in Wichita. The Company believes that the resolution of these claims will not have a material adverse effect on the consolidated financial statements.

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As a result of the crude oil discharge that occurred on July 1, 2007, the Company entered into an administrative order on consent (the Consent Order) with the Environmental Protection Agency (EPA) on July 10, 2007. As set forth in the Consent Order, the EPA concluded that the discharge of oil from the Company s refinery caused and may continue to cause an imminent and substantial threat to the public health and welfare. Pursuant to the Consent Order, the Company agreed to perform specified remedial actions to respond to the discharge of crude oil from the Company s refinery. The Company substantially completed remediating the damage caused by the crude oil discharge in July 2008. The substantial majority of all known remedial actions were completed by January 31, 2009. The Company is currently preparing its final report to the EPA to satisfy the final requirement of the Consent Order. The Company anticipates that the final report will be provided by June, 2009 with no further requirements resulting from the review of the report that could be material to the Company s business, financial condition, or results of operations.

As of December 31, 2008, the total gross costs recorded associated with remediation and third party property damage as a result of the crude oil discharge approximated $54,240,000. The Company has not estimated or accrued for any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from lawsuits related to the June/July 2007 flood as management does not believe any such fines, penalties or lawsuits would be material nor can be estimated.

While the remediation efforts were substantially completed in July 2008, the costs and damages that the Company will ultimately pay may be greater than the amounts described and projected above. Such excess costs and damages could be material to the consolidated financial statements.

The Company is seeking insurance coverage for this release and for the ultimate costs for remediation and property damage claims. The Company s excess environmental liability insurance carrier has asserted that its pollution liability claims are for cleanup, which is not covered by such policy, rather than for property damage, which is covered to the limits of the policy. While the Company will vigorously contest the excess carrier s position, it contends that if that position were upheld, its umbrella Comprehensive General Liability policies would continue to provide coverage for these claims. Each insurer, however, has reserved its rights under various policy exclusions and limitations and has cited potential coverage defenses. Although the Company believes that certain amounts under the environmental and liability insurance policies will be recovered, the Company cannot be certain of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of the Company s claims. The Company received $10,000,000 of insurance proceeds under its primary environmental liability insurance policy in 2007 and received an additional $15,000,000 in September 2008 from that carrier, which two payments together constituted full payment to the Company of the primary pollution liability policy limit.

On July 10, 2008, the Company filed two lawsuits in the United States District Court for the District of Kansas against certain of the Company s environmental and property insurance carriers with regard to the Company s insurance coverage for the June/July 2007 flood and crude oil discharge. The lawsuit with the insurance carriers under the environmental policies remains the only unsettled lawsuit with the insurance carriers. The property insurance lawsuit has been settled and dismissed.

Environmental, Health, and Safety (EHS) Matters

CVR is subject to various stringent federal, state, and local EHS rules and regulations. Liabilities related to EHS matters are recognized when the related costs are probable and can be reasonably estimated. Estimates of these costs are based upon currently available facts, existing technology, site-specific costs, and currently enacted laws and regulations. In reporting EHS liabilities, no offset is made for potential recoveries. Such liabilities include estimates of CVR s share of costs attributable to potentially responsible parties which are insolvent or otherwise unable to pay. All liabilities are monitored and adjusted regularly as new facts emerge or changes in law or technology occur.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Through an Administrative Order issued to Original Predecessor under the Resource Conservation and Recovery Act, as amended (RCRA), CVR is a potential party responsible for conducting corrective actions at its Coffeyville, Kansas and Phillipsburg, Kansas facilities. In 2005, CRNF agreed to participate in the State of Kansas Voluntary Cleanup and Property Redevelopment Program (VCPRP) to address a reported release of urea ammonium nitrate (UAN) at the Coffeyville UAN loading rack. As of December 31, 2008 and 2007, environmental accruals of $6,924,000 and $7,646,000, respectively, were reflected in the consolidated balance sheets for probable and estimated costs for remediation of environmental contamination under the RCRA Administrative Order and the VCPRP, including amounts totaling $2,684,000 and $2,802,000, respectively, included in other current liabilities. The CVR accruals were determined based on an estimate of payment costs through 2031, which scope of remediation was arranged with the EPA and are discounted at the appropriate risk free rates at December 31, 2008 and 2007, respectively. The accruals include estimated closure and post-closure costs of $1,124,000 and $1,549,000 for two landfills at December 31, 2008 and 2007, respectively. The estimated future payments for these required obligations are as follows (in thousands):

Year Ending December 31,	**Amount**
2009	$ 2,684
2010	1,013
2011	516
2012	313
2013	313
Thereafter	2,682
Undiscounted total	7,521
Less amounts representing interest at 2.06%	597
Accrued environmental liabilities at December 31, 2008	$ 6,924

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

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 the Company approval under a hardship waiver that would defer 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. The Company completed the construction and startup phase of our ULSD Hydrodesulfurization unit in late 2006 and met the conditions of the hardship waiver. The Company is 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 $13,787,000 during 2008, approximately $16,800,000 during 2007 and $79,033,000 during 2006. Based on information currently available, CVR anticipates spending approximately $27 million in 2009, $19 million in 2010, and $5 million in 2011 to comply with ULSG and ULSD requirements. The entire amounts are expected to be capitalized

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. For the years ended December 31, 2008, 2007 and 2006 capital expenditures were

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approximately $39,688,000, $122,341,000, and $144,794,000, respectively, and were incurred to improve the environmental compliance and efficiency of the operations.

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

(15) Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement established a single authoritative definition of fair value when accounting rules require the use of fair value, set out a framework for measuring fair value, and required additional disclosures about fair value measurements. SFAS 157 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants.

The Company adopted SFAS 157 on January 1, 2008 with the exception of nonfinancial assets and nonfinancial liabilities that were deferred by FASB Staff Position 157-2 as discussed in Note 2. As of December 31, 2008, the Company has not applied SFAS 157 to goodwill and intangible assets in accordance with FASB Staff Position 157-2.

SFAS 157 discusses valuation techniques, such as the market approach (prices and other relevant information generated by market conditions involving identical or comparable assets or liabilities), the income approach (techniques to convert future amounts to single present amounts based on market expectations including present value techniques and option-pricing), and the cost approach (amount that would be required to replace the service capacity of an asset which is often referred to as replacement cost). SFAS 157 utilizes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

Level 1 Quoted prices in active market for identical assets and liabilities

Level 2 Other significant observable inputs (including quoted prices in active markets for similar assets or liabilities)

Level 3 Significant unobservable inputs (including the Company s own assumptions in determining the fair value)

The following table sets forth the assets and liabilities measured at fair value on a recurring basis, by input level, as of December 31, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total
Cash Flow Swap		$ 38,262		$ 38,262
Interest Rate Swap		(7,789)		(7,789)

The Company s derivative contracts giving rise to assets or liabilities under Level 2 are valued using pricing models based on other significant observable inputs. Excluded from the table above is the Company s payable to swap counterparty totaling $62,375,000 at December 31, 2008, as this amount is not subject to the provisions of SFAS 157. This payable to swap counterparty relates to the J. Aron deferral. See Note 17 for further information regarding the deferral.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) Derivative Financial Instruments

Gain (loss) on derivatives, net consisted of the following:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Realized loss on swap agreements	$ (110,388)	$ (157,239)	$ (46,768)
Unrealized gain (loss) on swap agreements	253,195	(103,212)	126,771
Realized gain (loss) on other agreements	(10,582)	(15,346)	8,361
Unrealized gain (loss) on other agreements	634	(1,348)	2,411
Realized gain (loss) on interest rate swap agreements	(1,593)	4,115	4,398
Unrealized gain (loss) on interest rate swap agreements	(5,920)	(8,948)	(680)
Total gain (loss) on derivatives, net	$ 125,346	$ (281,978)	$ 94,493

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

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

Cash Flow Swap

At December 31, 2007, CVR s Petroleum Segment held commodity derivative contracts (swap agreements) for the period from July 1, 2005 to June 30, 2010 with a related party (see Note 17). The swap agreements were originally executed on June 16, 2005 in conjunction with the acquisition by CALLC of all outstanding stock held by Coffeyville Group Holdings, LLC and required under the terms of the long-term debt agreements. The notional quantities on the date of execution were 100,911,000 barrels of crude oil; 2,348,802,750 gallons of unleaded gasoline and 1,889,459,250 gallons of heating oil. The swap agreements were executed at the prevailing market rate at the time of execution and Management believes the swap agreements provide an economic hedge on future transactions. At December 31, 2008 the notional open amounts under the swap agreements were 17,696,250 barrels of crude oil;

371,621,250 gallons of unleaded gasoline and 371,621,250 gallons of heating oil. These positions result in unrealized gains (losses), using a valuation method that utilizes quoted market prices and assumptions for the estimated forward yield curves of the related commodities in periods when quoted market prices are unavailable. All of the activity related to the commodity derivative contracts is reported in the Petroleum Segment.

Interest Rate Swap

At December 31, 2008, CVR held derivative contracts known as interest rate swap agreements that converted CVR s floating-rate bank debt (see Note 11) into 4.195% fixed-rate debt on a notional amount of $250,000,000. Half of the agreements are held with a related party (as described in Note 17), and the other

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

half are held with a financial institution that is a lender under CVR s long-term debt agreements. The swap agreements carry the following terms:

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

CVR pays the fixed rates listed above and receives a floating rate based on three month LIBOR rates, with payments calculated on the notional amounts listed above. The notional amounts do not represent actual amounts exchanged by the parties but instead represent the amounts on which the contracts are based. The swap is settled quarterly and marked to market at each reporting date, and all unrealized gains and losses are currently recognized in income. Transactions related to the interest rate swap agreements were not allocated to the Petroleum or Nitrogen Fertilizer segments. Mark to market net gains (losses) on derivatives and quarterly settlements were $(7,513,000), $(4,833,000), and $3,718,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

(17) Related Party Transactions

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

Management Services Agreements

On June 24, 2005, CALLC entered into management services agreements with each of GS and Kelso pursuant to which GS and Kelso agreed to provide CALLC with managerial and advisory services. In consideration for these services, an annual fee of $1,000,000 each was paid to GS and Kelso, plus reimbursement for any out-of-pocket expenses. The agreements had a term ending on the date GS and Kelso ceased to own any interests in CALLC. Relating to the agreements, $1,704,000 and $2,316,000 were expensed in selling, general, and administrative expenses (exclusive of depreciation and amortization) for the years ended December 31, 2007 and 2006, respectively. The agreements terminated upon consummation of CVR s initial public offering on October 26, 2007. The Company paid a one-time fee of $5,000,000 to each of GS and Kelso by reason of such termination on October 26, 2007.

Cash Flow Swap

CRLLC entered into certain crude oil, heating oil, and gasoline swap agreements with a subsidiary of GS. These agreements were entered into on June 16, 2005, with an expiration date of June 30, 2010 (as described in Note 16). Amounts totaling $142,807,000, ($260,451,000), and $80,003,000 were reflected in gain (loss) on derivatives, net, related to these swap agreements for the years ended December 31, 2008, 2007 and 2006, respectively. In addition, the consolidated balance sheet at December 31, 2008 and 2007 includes liabilities of $62,375,000 and $262,415,000 included in current payable to swap counterparty and $0 and $88,230,000 included in long-term payable to swap counterparty, respectively. As of December 31, 2008, the Company recorded a short-term and long-term receivable from swap counterparty for $32,630,000 and $5,632,000, respectively, for the unrealized gain on the cash flow swap as of December 31, 2008. The short-term receivable was partially offset by a realized loss from the fourth quarter of 2008 for $2,641,000.

J. Aron Deferrals

As a result of the June/July 2007 flood and the temporary cessation of business operations in 2007, the Company entered into three separate deferral agreements for amounts owed to J. Aron. The amounts deferred,

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

excluding accrued interest, totaled $123,681,000. Of the original deferred balances, $61,306,000 has been repaid as of December 31, 2008. This deferred balance is included in the Consolidated Balance Sheet at December 31, 2008 in current payable to swap counterparty. The deferred balance owed to the GS subsidiary, excluding accrued interest payable, totaled $62,375,000 at December 31, 2008.

On July 29, 2008, CRLLC entered into a revised letter agreement with J. Aron to defer $87,500,000 of the deferred payment amounts under the 2007 deferral agreements. On August 29, 2008, the Company paid $36,181,000 of the balance to J. Aron, as well as $7,056,000 in accrued interest.

The deferral agreement was further amended on October 11, 2008 and the outstanding balance of $72,500,000 on that date was further deferred to July 31, 2009. Additional proceeds under the property insurance policy were used to pay down the principal balance on the deferral amount to $62,375,000.

These deferred payment amounts are included in the consolidated balance sheet at December 31, 2008 in current payable to swap counterparty. Interest relating to the deferred payment amounts reflected in interest expense and other financing costs for the year ended December 31, 2008 and 2007 were $4,812,000 and $3,625,000, respectively. Accrued interest related to the deferral agreement for the years ended December 31, 2008 and 2007 were $202,000 and $3,625,000, respectively, and are included in other current liabilities.

In January and February 2009, the Company prepaid $46,316,000 of the deferral obligations reducing the total principal deferred obligation to $16,059,000. On March 2, 2009, the remaining principal balance of $16,059,000 was paid in full including accrued interest of $509,000 resulting in the Company being unconditionally and irrevocably released from any and all of its obligations under the deferral agreements. In addition, J. Aron agreed to release the Goldman Sachs Funds and the Kelso Fund from any and all of their obligations to guarantee the deferred payment obligations.

Interest Rate Swap

On June 30, 2005, CVR entered into three interest-rate swap agreements with the same subsidiary of GS (as described in Note 16). Amounts totaling ($3,761,000), ($2,405,000), and $1,858,000 are recognized in gain (loss) on derivatives, net, related to these swap agreements for the years ended December 31, 2008, 2007 and 2006, respectively. In addition, the consolidated balance sheet at December 31, 2008 and 2007 includes $2,595,000 and $371,000 in other current liabilities and $1,298,000 and $557,000 in other long-term liabilities related to the same agreements, respectively.

Crude Oil Supply Agreement

Effective December 30, 2005, CVR entered into a crude oil supply agreement with a subsidiary of GS (Supplier). Under the agreement, both parties agreed to negotiate the cost of each barrel of crude oil to be purchased from a third party. The parties further agreed to negotiate the cost of each barrel of crude oil to be purchased from a third party, and CVR agreed to pay the supplier a fixed supply service fee per barrel over the negotiated cost of each barrel of crude purchased. The cost is adjusted further using a spread adjustment calculation based on the time period the crude oil is estimated to be delivered to the refinery, other market conditions, and other factors deemed appropriate. The monthly spread quantity for any delivery month at any time shall not exceed approximately 3.1 million barrels.

$8,211,000 and $360,000 were recorded on the consolidated balance sheet at December 31, 2008 and 2007, respectively, in prepaid expenses and other current assets for prepayment of crude oil. In addition, $20,063,000 and $43,773,000 were recorded in inventory and $2,757,000 and $42,666,000 were recorded in accounts payable at December 31, 2008 and 2007, respectively. Expenses associated with this agreement, included in cost of product sold (exclusive of depreciated and amortization) for the years ended December 31, 2008, 2007 and 2006 totaled $3,006,614,000, $1,477,000,000 and $1,591,120,000, respectively. The crude oil supply agreement was terminated with the subsidiary of GS

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effective December 31, 2008. The Company entered into a new crude oil supply agreement with Vitol Inc., an unrelated party, effective December 31, 2008, with a termination date two years from the effective date.

Cash and Cash Equivalents

The Company opened a highly liquid money market account with average maturities of less than ninety days with the Goldman Sachs Fund family in September 2008. As of December 31, 2008, the balance in the account was approximately $149,000. This amount also represented the interest income earned for 2008.

Financing and Other

An affiliate of GS was one of the lenders in conjunction with the refinancing of the credit facility that occurred on December 28, 2006. The Company paid this affiliate of GS an $8,063,000 fee and expense reimbursements of $78,000 included in deferred financing costs.

On August 23, 2007, the Company s subsidiaries entered into three new credit facilities, consisting of a $25,000,000 secured facility, a $25,000,000 unsecured facility and a $75,000,000 unsecured facility. A subsidiary of GS was the sole lead arranger and sole bookrunner for each of these new credit facilities. These credit facilities and their arrangements are more fully described in Note 11, Long-Term Debt . The Company paid the subsidiary of GS a $1,258,000 fee included in deferred financing costs. For the year ended December 31, 2007, interest expenses relating to these agreements were $867,000. The secured and unsecured facilities were paid in full on October 26, 2007 with proceeds from CVR s initial public offering, see Note 1, Organization and History of Company , and all three facilities terminated.

Goldman, Sachs & Co. was the lead underwriter of CVR s initial public offering in October 2007. As lead underwriter, they were paid a customary underwriting discount of approximately $14,710,000, which included $709,000 of expense reimbursement.

An affiliate of GS was a joint lead arranger and joint lead bookrunner in conjunction with CRLLC s amendment of their outstanding credit facility. In December 2008, CRLLC paid the subsidiary of GS a fee of $1,000,000 in connection with their services related to the amendment. Additionally, the Company paid a lender fee of approximately $52,000 in conjunction with this amendment to the subsidiary of GS. The affiliate is one of many lenders under the credit facility.

On October 24, 2007, CVR paid a cash dividend, to its shareholders, including approximately $5,228,000 that was ultimately distributed from CALLC II (Goldman Sachs Funds) and approximately $5,146,000 distributed from CALLC to the Kelso Funds. Management collectively received approximately $135,000.

For 2008, the Company purchased approximately $1,077,000 of FCC additives, a catalyst, from Intercat, Inc. A director of the Company, Mr. Regis Lippert, is also the Director, President, CEO and majority shareholder of Intercat, Inc.

(18) Business Segments

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

CVR changed its corporate selling, general and administrative allocation method to the operating segments in 2007. The effect of the change on operating income for the year ended December 31, 2006 would have been a decrease of $6,011,000 to the petroleum segment and an increase of $6,011,000 to the nitrogen fertilizer segment, respectively.

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Petroleum

Principal products of the Petroleum Segment are refined fuels, propane, and petroleum refining by-products including pet coke. CVR sells the pet coke to the Partnership for use in the manufacturing of nitrogen fertilizer at the adjacent nitrogen fertilizer plant. For CVR, a per-ton transfer price is used to record intercompany sales on the part of the Petroleum Segment and corresponding intercompany cost of product sold (exclusive of depreciation and amortization) for the Nitrogen Fertilizer Segment. The per ton transfer price paid, pursuant to the coke supply agreement that became effective October 24, 2007, is based on the lesser of a coke price derived from the price received by the fertilizer segment for UAN (subject to a UAN based price ceiling and floor) and a coke price index for pet coke. Prior to October 25, 2007 intercompany sales were based upon a price of $15 per ton. The intercompany transactions are eliminated in the Other Segment. Intercompany sales included in petroleum net sales were $12,080,000, $5,195,000, and $5,340,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Intercompany cost of product sold (exclusive of depreciation and amortization) for the hydrogen sales described below under Nitrogen Fertilizer was $8,967,000, $17,812,000 and $6,820,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Nitrogen Fertilizer

The principal product of the Nitrogen Fertilizer Segment is nitrogen fertilizer. Intercompany cost of product sold (exclusive of depreciation and amortization) for the coke transfer described above was $11,084,000, $4,528,000, and $5,242,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

Beginning in 2008, the Nitrogen Fertilizer Segment changed the method of classification of intercompany hydrogen sales to the Petroleum Segment. In 2008, these amounts have been reflected as Net Sales for the fertilizer plant. Prior to 2008, the Nitrogen Fertilizer Segment reflected these transactions as a reduction of cost of product sold (exclusive of deprecation and amortization). For the years ended December 31, 2008, 2007 and 2006, the net sales generated from intercompany hydrogen sales were $8,967,000, $17,812,000 and $6,820,000, respectively. As noted above, the net sales of $17,812,000 and $6,820,000 were included as a reduction to cost of product sold (exclusive of depreciation and amortization) for the years ended December 31, 2007 and 2006. As these intercompany sales are eliminated, there is no financial statement impact on the consolidated financial statements.

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Segment

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

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Net sales			
Petroleum	$ 4,774,337	$ 2,806,203	$ 2,880,442
Nitrogen Fertilizer	262,950	165,856	162,465
Other			
Intersegment elimination	(21,184)	(5,195)	(5,340)
Total	$ 5,016,103	$ 2,966,864	$ 3,037,567
Cost of product sold (exclusive of depreciation and amortization)			
Petroleum	$ 4,449,422	$ 2,300,226	$ 2,422,718
Nitrogen Fertilizer	32,574	13,042	25,899
Other			
Intersegment elimination	(20,188)	(4,528)	(5,242)
Total	$ 4,461,808	$ 2,308,740	$ 2,443,375
Direct operating expenses (exclusive of depreciation and amortization)			
Petroleum	$ 151,377	$ 209,474	$ 135,297
Nitrogen Fertilizer	86,092	66,663	63,683
Other			
Total	$ 237,469	$ 276,137	$ 198,980
Net costs associated with flood			
Petroleum	$ 6,380	$ 36,669	$
Nitrogen Fertilizer	27	2,432	
Other	1,456	2,422	
Total	$ 7,863	$ 41,523	$
Depreciation and amortization			
Petroleum	$ 62,690	$ 43,040	$ 33,016
Nitrogen Fertilizer	17,987	16,819	17,126

Other		1,500		920		862
Total	$	82,177	$	60,779	$	51,004
Goodwill Impairment						
Petroleum	$	42,806	$		$	
Nitrogen Fertilizer						
Other						
Total	$	42,806	$		$	

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Operating income (loss)			
Petroleum	31,902	144,876	245,578
Nitrogen Fertilizer	116,807	46,593	36,842
Other	32	(4,906)	(812)
Total	$ 148,741	$ 186,563	$ 281,608
Capital expenditures			
Petroleum	$ 60,410	$ 261,562	$ 223,553
Nitrogen fertilizer	24,076	6,488	13,258
Other	1,972	543	3,414
Total	$ 86,458	$ 268,593	$ 240,225
Total assets			
Petroleum	$ 1,032,223	$ 1,277,124	
Nitrogen Fertilizer	644,301	446,763	
Other	(66,041)	144,469	
Total	$ 1,610,483	$ 1,868,356	
Goodwill			
Petroleum	$	$ 42,806	
Nitrogen Fertilizer	40,969	40,969	
Other			
Total	$ 40,969	$ 83,775	

(19) Major Customers and Suppliers

Sales to major customers were as follows:

	Year Ended December 31, 2008	2007	2006
Petroleum			

Customer A	13%	12%	15%
Customer B	3%	7%	10%
Customer C	10%	9%	10%
Customer D	9%	10%	9%
	35%	38%	44%
Nitrogen Fertilizer			
Customer E	13%	18%	7%

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Petroleum Segment through December 31, 2008 maintained a long-term contract with one supplier, a related party (as described in Note 17), for the purchase of its crude oil. Purchases contracted as a percentage of the total cost of product sold (exclusive of depreciation and amortization) for each of the periods were as follows:

	Year Ended December 31,		
	2008	2007	2006
Supplier	67%	63%	67%

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

	Year Ended December 31,		
	2008	2007	2006
Supplier	5%	5%	8%

CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(20) Selected Quarterly Financial and Information (Unaudited)

Summarized quarterly financial data for December 31, 2008 and 2007.

	Year Ended December 31, 2008 Quarter			
	First	Second	Third	Fourth
	(In thousands except share data)			
Net sales	$ 1,223,003	$ 1,512,503	$ 1,580,911	$ 699,686
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	1,036,194	1,287,477	1,440,355	697,782
Direct operating expenses (exclusive of depreciation and amortization)	60,556	62,336	56,575	58,002
Selling, general and administrative (exclusive of depreciation and amortization)	13,497	14,762	(7,820)	14,800
Net costs associated with flood	5,763	3,896	(817)	(979)
Depreciation and amortization	19,635	21,080	20,609	20,853
Goodwill impairment				42,806
Total operating costs and expenses	1,135,645	1,389,551	1,508,902	833,264
Operating income (loss)	87,358	122,952	72,009	(133,578)
Other income (expense):				
Interest expense and other financing costs	(11,298)	(9,460)	(9,333)	(10,222)
Interest income	702	601	257	1,135
Gain (loss) on derivatives, net	(47,871)	(79,305)	76,706	175,816
Loss on extinguishment of debt				(9,978)
Other income (expense), net	179	251	428	497
Total other income (expense)	(58,288)	(87,913)	68,058	157,248
Income before income taxes and minority interest in subsidiaries	29,070	35,039	140,067	23,670
Income tax expense	6,849	4,051	40,411	12,600
Minority interest in (income) loss of subsidiaries				
Net income	$ 22,221	$ 30,988	$ 99,656	$ 11,070
Net earnings per share				
Basic	$ 0.26	$ 0.36	$ 1.16	$ 0.13

Diluted	$ 0.26	$ 0.36	$ 1.16	$ 0.13
Weighted average common shares outstanding				
Basic	86,141,291	86,141,291	86,141,291	86,158,206
Diluted	86,158,791	86,158,791	86,158,791	86,236,872

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CVR Energy, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Quarterly Financial Information (Unaudited)

	Year Ended December 31, 2007 Quarter			
	First	**Second**	**Third**	**Fourth**
Net sales	$ 390,483	$ 843,413	$ 585,978	$ 1,146,990
Operating costs and expenses:				
Cost of product sold (exclusive of depreciation and amortization)	303,670	569,623	453,242	982,205
Direct operating expenses (exclusive of depreciation and amortization)	113,412	60,955	44,440	57,330
Selling, general and administrative (exclusive of depreciation and amortization)	13,150	14,937	14,035	51,000
Net costs associated with flood		2,139	32,192	7,192
Depreciation and amortization	14,235	17,957	10,481	18,106
Goodwill impairment				
Total operating costs and expenses	444,467	665,611	554,390	1,115,833
Operating income (loss)	(53,984)	177,802	31,588	31,157
Other income (expense):				
Interest expense and other financing costs	(11,857)	(15,763)	(18,340)	(15,166)
Interest income	452	161	151	336
Gain (loss) on derivatives, net	(136,959)	(155,485)	40,532	(30,066)
Loss on extinguishment of debt				(1,258)
Other income (expense), net	1	101	53	201
Total other income (expense)	(148,363)	(170,986)	22,396	(45,953)
Income (loss) before income taxes and minority interest in subsidiaries	(202,347)	6,816	53,984	(14,796)
Income tax expense (benefit)	(47,298)	(93,669)	42,731	9,721
Minority interest in (income) loss of subsidiaries	676	(419)	(47)	
Net income (loss)	$ (154,373)	$ 100,066	$ 11,206	$ (24,517)
Pro Forma Information				
Net earnings (loss) per share				
Basic	$ (1.79)	$ 1.16	$ 0.13	$ (0.28)
Diluted	$ (1.79)	$ 1.16	$ 0.13	$ (0.28)

Weighted average common shares outstanding				
Basic	86,141,291	86,141,291	86,141,291	86,141,291
Diluted	86,141,291	86,158,791	86,158,791	86,141,291

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

None.

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

Evaluation of Disclosure Controls and Procedures. As of December 31, 2008, we have evaluated, under the direction of our Chief Executive Officer and Chief Financial Officer, the effectiveness of the Company s disclosure controls and procedures, as defined in Exchange Act Rule 13a-15(e). Based upon and as of the date of that evaluation, the Company s Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures, were effective to ensure that information required to be disclosed in the reports that the Company files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to the Company s management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting. There has been no change in the Company s internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2008 that has materially affected or is reasonably likely to materially affect, the Company s internal control over financial reporting, except that during the fourth quarter of 2008, we completed remediation efforts relating to a material weakness in our controls over accounting for the cost of crude oil that was reported as of December 31, 2007.

Management s Report On Internal Control Over Financial Reporting. We are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that the Company s internal control over financial reporting was effective as of December 31, 2008. Our independent registered public accounting firm, that audited the consolidated financial statements included herein under Item 8, has issued a report on the effectiveness of our internal control over financial reporting. This report can be found under Item 8.

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

None.

PART III

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

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

Item 11. ***Executive Compensation***

Information about executive and director compensation is included under the captions Corporate Governance Compensation Committee Interlocks and Insider Participation, Proposal 1 Election of Directors, Director Compensation for 2008, Compensation Discussion and Analysis, Compensation Committee Report and Compensation of Executive Officers contained in our proxy statement for the annual

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meeting of our stockholders, which will be filed with the SEC prior to April 30, 2009 and this information is incorporated herein by reference.

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

Information about security ownership of certain beneficial owners and management is included under the captions Compensation of Executive Officers Equity Compensation Plan Information and Securities Ownership of Certain Beneficial Owners and Officers and Directors contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC.

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

Information about related party transactions between CVR Energy (and its predecessors) and its directors, executive officers and 5% stockholders that occurred during the year ended December 31, 2008 is included under the captions Certain Relationships and Related Party Transactions and Corporate Governance The Controlled Company Exemption and Director Independence Director Independence contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2009, and this information is incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services***

Information about principal accounting fees and services is included under the captions Proposal 2 Ratification of Selection of Independent Registered Public Accounting Firm and Fees Paid to the Independent Registered Public Accounting Firm contained in our proxy statement for the annual meeting of our stockholders, which will be filed with the SEC prior to April 30, 2009, and this information is incorporated herein by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements

See Index to Consolidated Financial Statements.

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

Exhibit Number	Exhibit Title
3.1**	Amended and Restated Certificate of Incorporation of CVR Energy, Inc. (filed as Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).
3.2**	

	Amended and Restated Bylaws of CVR Energy, Inc. (filed as Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).
4.1**	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).

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Exhibit Number	Exhibit Title
10.1**	Second Amended and Restated Credit and Guaranty Agreement, dated as of December 28, 2006, among Coffeyville Resources, LLC and the other parties thereto (filed as Exhibit 10.1 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.1.1**	First Amendment to Second Amended and Restated Credit and Guaranty Agreement, dated as of August 23, 2007, among Coffeyville Resources, LLC and the other parties thereto (filed as Exhibit 10.1.1 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.1.2**	Second Amendment to Second Amended and Restated Credit and Guaranty Agreement dated December 22, 2008 between Coffeyville Resources, LLC, certain related parties, the Arrangers and Administrative Agent a party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K, filed on December 23, 2008 and incorporated herein by reference).
10.2**	Amended and Restated First Lien Pledge and Security Agreement, dated as of December 28, 2006, among Coffeyville Resources, LLC, CL JV Holdings, LLC, Coffeyville Pipeline, Inc., Coffeyville Refining and Marketing, Inc., Coffeyville Nitrogen Fertilizers, Inc., Coffeyville Crude Transportation, Inc., Coffeyville Terminal, Inc., Coffeyville Resources Pipeline, LLC, Coffeyville Resources Refining & Marketing, LLC, Coffeyville Resources Nitrogen Fertilizers, LLC, Coffeyville Resources Crude Transportation, LLC and Coffeyville Resources Terminal, LLC, as grantors, and Credit Suisse, as collateral agent (filed as Exhibit 10.2 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.3 **	Swap agreements with J. Aron & Company (filed as Exhibit 10.5 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.4 **	License Agreement For Use of the Texaco Gasification Process, Texaco Hydrogen Generation Process, and Texaco Gasification Power Systems, dated as of May 30, 1997 by and between Texaco Development Corporation and Farmland Industries, Inc., as amended (filed as Exhibit 10.4 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.5 **	Amended and Restated On-Site Product Supply Agreement dated as of June 1, 2005, between Linde, Inc. (f/k/a The BOC Group, Inc.) and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.6 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.5.1**	First Amendment to Amended and Restated On-Site Product Supply Agreement, dated as of October 31, 2008, between Coffeyville Resources Nitrogen Fertilizers, LLC and Linde, Inc. (filed as Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 and incorporated by reference herein).
10.6 *	Crude Oil Supply Agreement dated December 2, 2008 between Vitol Inc. and Coffeyville Resources Refining & Marketing, LLC.
10.6.1 *	First Amendment to Crude Oil Supply Agreement dated January 1, 2009 between Vitol Inc. and Coffeyville Resources Refining & Marketing, LLC.
10.7 **	Pipeline Construction, Operation and Transportation Commitment Agreement, dated February 11, 2004, as amended, between Plains Pipeline, L.P. and Coffeyville Resources Refining & Marketing, LLC (filed as Exhibit 10.14 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.8**	Electric Services Agreement dated January 13, 2004, between Coffeyville Resources Nitrogen Fertilizers, LLC and the City of Coffeyville, Kansas (filed as Exhibit 10.15 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.9**	

Purchase, Storage and Sale Agreement for Gathered Crude, dated as of March 20, 2007, between J. Aron & Company and Coffeyville Resources Refining & Marketing, LLC (filed as Exhibit 10.22 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).

Exhibit Number	Exhibit Title
10.10**	Stockholders Agreement of CVR Energy, Inc., dated as of October 16, 2007, by and among CVR Energy, Inc., Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC (filed as Exhibit 10.20 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.11**	Registration Rights Agreement, dated as of October 16, 2007, by and among CVR Energy, Inc., Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC (filed as Exhibit 10.21 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.12**	Management Registration Rights Agreement, dated as of October 24, 2007, by and between CVR Energy, Inc. and John J. Lipinski (filed as Exhibit 10.27 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.13**	Stock Purchase Agreement, dated as of May 15, 2005 by and between Coffeyville Group Holdings, LLC and Coffeyville Acquisition LLC (filed as Exhibit 10.23 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.13.1**	Amendment No. 1 to the Stock Purchase Agreement, dated as of June 24, 2005 by and between Coffeyville Group Holdings, LLC and Coffeyville Acquisition LLC (filed as Exhibit 10.23.1 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.13.2**	Amendment No. 2 to the Stock Purchase Agreement, dated as of July 25, 2005 by and between Coffeyville Group Holdings, LLC and Coffeyville Acquisition LLC (filed as Exhibit 10.23.2 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.14**	First Amended and Restated Agreement of Limited Partnership of CVR Partners, LP, dated as of October 24, 2007, by and among CVR GP, LLC and Coffeyville Resources, LLC (filed as Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).
10.15**	Coke Supply Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).
10.16**	Cross Easement Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.17**	Environmental Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.17.1**	Supplement to Environmental Agreement, dated as of February 15, 2008, by and between Coffeyville Resources Refining and Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.17.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.17.2**	Second Supplement to Environmental Agreement, dated as of July 23, 2008, by and between Coffeyville Resources Refining and Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30,

	2008 and incorporated by reference herein).
10.18**	Feedstock and Shared Services Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).

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Exhibit Number	Exhibit Title
10.19**	Raw Water and Facilities Sharing Agreement, dated as of October 25, 2007, by and between Coffeyville Resources Refining & Marketing, LLC and Coffeyville Resources Nitrogen Fertilizers, LLC (filed as Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.20**	Services Agreement, dated as of October 25, 2007, by and among CVR Partners, LP, CVR GP, LLC, CVR Special GP, LLC, and CVR Energy, Inc. (filed as Exhibit 10.10 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.21**	Omnibus Agreement, dated as of October 24, 2007 by and among CVR Energy, Inc., CVR GP, LLC, CVR Special GP, LLC and CVR Partners, LP (filed as Exhibit 10.11 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.22**	Contribution, Conveyance and Assumption Agreement, dated as of October 24, 2007, by and among Coffeyville Resources, LLC, CVR GP, LLC, CVR Special GP, LLC, and CVR Partners, LP (filed as Exhibit 10.25 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.23**	Registration Rights Agreement, dated as of October 24, 2007, by and among CVR Partners, LP, CVR Special GP, LLC and Coffeyville Resources, LLC (filed as Exhibit 10.24 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.24**	Amended and Restated Employment Agreement, dated as of January 1, 2008, by and between CVR Energy, Inc. and John J. Lipinski (filed as Exhibit 10.24 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.25**	Amended and Restated Employment Agreement, dated as of December 29, 2007, by and between CVR Energy, Inc. and Stanley A. Riemann (filed as Exhibit 10.25 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.26**	Amended and Restated Employment Agreement, dated as of December 29, 2007, by and between CVR Energy, Inc. and James T. Rens (filed as Exhibit 10.26 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.27**	Employment Agreement, dated as of October 23, 2007, by and between CVR Energy, Inc. and Daniel J. Daly, Jr. (filed as Exhibit 10.27 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.27.1**	First Amendment to Employment Agreement, dated as of November 30, 2007, by and between CVR Energy, Inc. and Daniel J. Daly, Jr. (filed as Exhibit 10.27.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.28**	Amended and Restated Employment Agreement, dated as of December 29, 2007, by and between CVR Energy, Inc. and Robert W. Haugen (filed as Exhibit 10.28 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
10.29**	CVR Energy, Inc. 2007 Long Term Incentive Plan (filed as Exhibit 10.13 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.29.1**	Form of Nonqualified Stock Option Agreement (filed as Exhibit 10.33.1 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.29.2**	Form of Director Stock Option Agreement (filed as Exhibit 10.33.2 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.29.3**	Form of Director Restricted Stock Agreement (filed as Exhibit 10.33.3 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).

Exhibit Number	Exhibit Title
10.30**	Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan I), as amended (filed as Exhibit 10.3 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.31**	Coffeyville Resources, LLC Phantom Unit Appreciation Plan (Plan II) (filed as Exhibit 10.12 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.32**	Stockholders Agreement of Coffeyville Nitrogen Fertilizer, Inc., dated as of March 9, 2007, by and among Coffeyville Nitrogen Fertilizers, Inc., Coffeyville Acquisition LLC and John J. Lipinski (filed as Exhibit 10.17 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.33**	Stockholders Agreement of Coffeyville Refining & Marketing Holdings, Inc., dated as of August 22, 2007, by and among Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Acquisition LLC and John J. Lipinski (filed as Exhibit 10.18 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.34**	Subscription Agreement, dated as of March 9, 2007, by Coffeyville Nitrogen Fertilizers, Inc. and John J. Lipinski (filed as Exhibit 10.19 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.35**	Subscription Agreement, dated as of August 22, 2007, by Coffeyville Refining & Marketing Holdings, Inc. and John J. Lipinski (filed as Exhibit 10.20 to the Company s Registration Statement on Form S-1, File No. 333-137588 and incorporated herein by reference).
10.36**	Amended and Restated Recapitalization Agreement, dated as of October 16, 2007, by and among Coffeyville Acquisition LLC, Coffeyville Refining & Marketing Holdings, Inc., Coffeyville Refining & Marketing, Inc., Coffeyville Nitrogen Fertilizers, Inc. and CVR Energy, Inc. (filed as Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarterly period September 30, 2007 and incorporated herein by reference).
10.37**	Subscription Agreement, dated as of October 16, 2007, by and between CVR Energy, Inc. and John J. Lipinski (filed as Exhibit 10.21 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.38**	Redemption Agreement, dated as of October 16, 2007, by and among Coffeyville Acquisition LLC and the Redeemed Parties signatory thereto (filed as Exhibit 10.19 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.39**	Third Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition LLC, dated as of October 16, 2007 (filed as Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.39.1**	Amendment No. 1 to the Third Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition LLC, dated as of October 16, 2007 (filed as Exhibit 10.15 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.40**	First Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition II LLC, dated as of October 16, 2007 (filed as Exhibit 10.16 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.40.1**	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition II LLC, dated as of October 16, 2007 (filed as Exhibit 10.17 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).

10.41**	Amended and Restated Limited Liability Company Agreement of Coffeyville Acquisition III LLC, dated as of February 15, 2008 (filed as Exhibit 10.41 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).

Exhibit Number	Exhibit Title
10.42**	Letter Agreement, dated as of October 24, 2007, by and among Coffeyville Acquisition LLC, Goldman, Sachs & Co. and Kelso & Company, L.P. (filed as Exhibit 10.23 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated by reference herein).
10.43*	Amended and Restated Employment Agreement, dated as of December 29, 2007, by and between CVR Energy, Inc. and Kevan A. Vick.
10.44*	Amended and Restated Employment Agreement, dated as of December 29, 2007, by and between CVR Energy, Inc. and Wyatt E. Jernigan.
10.45**	Consulting Agreement, dated May 2, 2008, by and between General Wesley Clark and CVR Energy, Inc. (filed as Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2008 and incorporated by reference herein).
10.46*	Amended and Restated Employment Agreement, dated as of December 29, 2007, by and between CVR Energy, Inc. and Edmund S. Gross.
10.47*	Separation Agreement dated January 23, 2009 between James T. Rens, CVR Energy, Inc. and Coffeyville Resources, LLC.
10.48*	LLC Unit Agreement dated January 23, 2009 between Coffeyville Acquisition, LLC, Coffeyville Acquisition II, LLC, Coffeyville Acquisition III, LLC and James T. Rens.
10.49*	Form of Indemnification Agreement between CVR Energy, Inc. and each of its directors and officers.
21.1**	List of Subsidiaries of CVR Energy, Inc. (filed as Exhibit 21.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated by reference herein).
23.1*	Consent of KPMG LLP.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1*	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer.

* Filed herewith.

** Previously filed.

Certain portions of this exhibit have been omitted and separately filed with the SEC pursuant to a request for confidential treatment which has been granted by the SEC.

Certain portions of this exhibit have been omitted and separately filed with the SEC pursuant to a request for confidential treatment which is pending at the SEC.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CVR Energy, Inc.

Date: March 13, 2009	By: /s/ John J. Lipinski Name: John J. Lipinski Title: Chief Executive Officer

Pursuant to the requirements of the Exchange Act, this report had been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Title	Date
/s/ John J. Lipinski John J. Lipinski	Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)	March 13, 2009
/s/ James T. Rens James T. Rens	Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 13, 2009
/s/ Scott Hobbs Scott Hobbs	Director	March 13, 2009
/s/ Scott L. Lebovitz Scott L. Lebovitz	Director	March 13, 2009
/s/ Regis B. Lippert Regis B. Lippert	Director	March 13, 2009
/s/ George E. Matelich George E. Matelich	Director	March 13, 2009
/s/ Steve A. Nordaker Steve A. Nordaker	Director	March 13, 2009

/s/ Stanley de J. Osborne Stanley de J. Osborne	Director	March 13, 2009
/s/ Kenneth A. Pontarelli Kenneth A. Pontarelli	Director	March 13, 2009
/s/ Mark Tomkins Mark Tomkins	Director	March 13, 2009

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