CVR ENERGY INC
Form 10-Q
May 15, 2008

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**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
**FORM 10-Q**

**(Mark One)**

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended March 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** | **61-1512186** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **2277 Plaza Drive, Suite 500 Sugar Land, Texas** | **77479** |
| (Address of principal executive offices) | (Zip Code) |

Registrant s telephone number, including area code: **(281) 207-3200**

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

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

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

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

There were 86,141,291 shares of the registrant s common stock outstanding at May 13, 2008.

**CVR ENERGY, INC. AND SUBSIDIARIES**
**INDEX TO QUARTERLY REPORT ON FORM 10-Q**
**For The Quarter Ended March 31, 2008**

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## PART I. FINANCIAL INFORMATION
## ITEM 1. FINANCIAL STATEMENTS

### CVR ENERGY, INC. AND SUBSIDIARIES
### CONDENSED CONSOLIDATED BALANCE SHEETS
### (in thousands of dollars)

| | March 31, 2008 (unaudited) | December 31, 2007 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 25,179 | $ 30,509 |
| Accounts receivable, net of allowance for doubtful accounts of $597 and $391, respectively | 117,033 | 86,546 |
| Inventories | 288,415 | 254,655 |
| Prepaid expenses and other current assets | 13,071 | 14,186 |
| Insurance receivable | 74,275 | 73,860 |
| Income tax receivable | 26,166 | 31,367 |
| Deferred income taxes | 78,325 | 79,047 |
| Total current assets | 622,464 | 570,170 |
| Property, plant, and equipment, net of accumulated depreciation | 1,192,542 | 1,192,174 |
| Intangible assets, net | 450 | 473 |
| Goodwill | 83,775 | 83,775 |
| Deferred financing costs, net | 7,028 | 7,515 |
| Insurance receivable | 11,400 | 11,400 |
| Other long-term assets | 5,932 | 2,849 |
| Total assets | $ 1,923,591 | $ 1,868,356 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Current portion of long-term debt | $ 4,862 | $ 4,874 |
| Note payable and capital lease obligations | 11,209 | 11,640 |
| Payable to swap counterparty | 294,984 | 262,415 |
| Accounts payable | 170,194 | 182,225 |
| Personnel accruals | 34,954 | 36,659 |
| Accrued taxes other than income taxes | 22,073 | 14,732 |
| Deferred revenue | 29,784 | 13,161 |
| Other current liabilities | 32,953 | 33,820 |
| Total current liabilities | 601,013 | 559,526 |
| Long-term liabilities: | | |
| Long-term debt, less current portion | 483,117 | 484,328 |
| Accrued environmental liabilities | 4,924 | 4,844 |

| | | |
|---|---|---|
| Deferred income taxes | 287,974 | 286,986 |
| Other long-term liabilities | 4,447 | 1,122 |
| Payable to swap counterparty | 76,411 | 88,230 |
| Total long-term liabilities | 856,873 | 865,510 |
| Commitments and contingencies | | |
| Minority interest in subsidiaries | 10,600 | 10,600 |
| Stockholders equity | | |
| Common stock $0.01 par value per share; 350,000,000 shares authorized; 86,141,291 shares issued and outstanding | 861 | 861 |
| Additional paid-in-capital | 458,523 | 458,359 |
| Retained earning (deficit) | (4,279) | (26,500) |
| Total stockholders equity | 455,105 | 432,720 |
| Total liabilities and stockholders equity | $ 1,923,591 | $ 1,868,356 |

See accompanying notes to the condensed consolidated financial statements.

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**CVR ENERGY, INC. AND SUBSIDIARIES**
**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**
**(unaudited)**
**(in thousands except share amounts)**

| | Three months ended March 31, 2008 | Three months ended March 31, 2007 |
|---|---|---|
| Net sales | $ 1,223,003 | $ 390,483 |
| Operating costs and expenses: | | |
| Cost of product sold (exclusive of depreciation and amortization) | 1,036,194 | 303,670 |
| Direct operating expenses (exclusive of depreciation and amortization) | 60,556 | 113,412 |
| Selling, general and administrative expenses (exclusive of depreciation and amortization) | 13,497 | 13,150 |
| Net costs associated with flood | 5,763 | |
| Depreciation and amortization | 19,635 | 14,235 |
| Total operating costs and expenses | 1,135,645 | 444,467 |
| Operating income (loss) | 87,358 | (53,984) |
| Other income (expense): | | |
| Interest expense and other financing costs | (11,298) | (11,857) |
| Interest income | 702 | 452 |
| Loss on derivatives, net | (47,871) | (136,959) |
| Other income, net | 179 | 1 |
| Total other income (expense) | (58,288) | (148,363) |
| Income (loss) before income taxes and minority interest in subsidiaries | 29,070 | (202,347) |
| Income tax expense (benefit) | 6,849 | (47,298) |
| Minority interest in loss of subsidiaries | | 676 |
| Net income (loss) | $ 22,221 | $ (154,373) |
| Net earnings per share | | |
| Basic | $ 0.26 | |
| Diluted | $ 0.26 | |
| Weighted average common shares outstanding | | |
| Basic | 86,141,291 | |
| Diluted | 86,158,791 | |
| Pro Forma Information (note 11) | | |
| Net (loss) per share | | |
| Basic | | $ (1.79) |

| | | |
|---|---|---|
| Diluted | $ | (1.79) |
| Weighted average common shares outstanding | | |
| Basic | | 86,141,291 |
| Diluted | | 86,141,291 |

See accompanying notes to the condensed consolidated financial statements.

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**CVR ENERGY, INC. AND SUBSIDIARIES**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(unaudited)**
**(in thousands of dollars)**

| | Three months ended March 31, 2008 | Three months ended March 31, 2007 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income (loss) | $ 22,221 | $ (154,373) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation and amortization | 19,635 | 14,235 |
| Provision for doubtful accounts | 206 | (235) |
| Amortization of deferred financing costs | 495 | 473 |
| Loss on disposition of fixed assets | 16 | 24 |
| Share-based compensation | (383) | 3,742 |
| Minority interest in loss of subsidiaries | | (676) |
| Changes in assets and liabilities: | | |
| Accounts receivable | (30,693) | 44,627 |
| Inventories | (31,642) | (22,986) |
| Prepaid expenses and other current assets | 75 | 31 |
| Insurance receivable | 1,085 | |
| Insurance proceeds from flood | (1,500) | |
| Other long-term assets | (3,159) | 923 |
| Accounts payable | (5,166) | 46,357 |
| Accrued income taxes | 5,201 | 14,888 |
| Deferred revenue | 16,623 | 5,067 |
| Other current liabilities | 5,315 | 3,470 |
| Payable to swap counterparty | 20,750 | 129,344 |
| Accrued environmental liabilities | 80 | 485 |
| Other long-term liabilities | 3,325 | |
| Deferred income taxes | 1,710 | (41,291) |
| Net cash provided by operating activities | 24,194 | 44,105 |
| Cash flows from investing activities: | | |
| Capital expenditures | (26,156) | (107,363) |
| Net cash used in investing activities | (26,156) | (107,363) |
| Cash flows from financing activities: | | |
| Revolving debt payments | (123,000) | |
| Revolving debt borrowings | 123,000 | 29,500 |
| Principal payments on long-term debt | (1,223) | |
| Deferred costs of CVR Energy, Inc. initial public offering | | (553) |
| Deferred costs of CVR Partners, LP initial public offering | (2,145) | |

| | | |
|---|---|---|
| Net cash (used in) provided by financing activities | (3,368) | 28,947 |
| Net decrease in cash and cash equivalents | (5,330) | (34,311) |
| Cash and cash equivalents, beginning of period | 30,509 | 41,919 |
| Cash and cash equivalents, end of period | $ 25,179 | $ 7,608 |
| Supplemental disclosures: | | |
| Cash paid for income taxes, net of refunds (received) | $ (63) | $ (20,895) |
| Cash paid for interest | 11,841 | 39 |
| Non-cash investing and financing activities: | | |
| Accrual of construction in progress additions | (6,237) | 13,204 |

See accompanying notes to the condensed consolidated financial statements.

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**CVR ENERGY, INC. AND SUBSIDIARIES**
**NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**
**MARCH 31, 2008**
**(unaudited)**

## (1) Organization and History of the Company and Basis of Presentation

***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 after June 24, 2005 and prior to October 16, 2007 (the date of the restructuring as further discussed in this note) are to Coffeyville Acquisition LLC (CALLC) and its subsidiaries.

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. The initial public offering of CVR was consummated on October 26, 2007. In conjunction with the initial public offering, a restructuring occurred in which CVR became a direct or indirect owner of all of the subsidiaries of CALLC. Additionally, in connection with the initial public offering, CALLC was split into two entities: Coffeyville Acquisition LLC and Coffeyville Acquisition II LLC (CALLC II).

***Initial Public Offering of CVR Energy, Inc.***

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

The net proceeds to CVR from the initial public offering were approximately $408.5 million, after deducting underwriting discounts and commissions, but before deduction of offering expenses. The Company also incurred approximately $11.4 million of other costs related to the initial public offering. The net proceeds from this offering were used to repay $280.0 million of term debt under the Company s credit facility and to repay all indebtedness under the Company s $25.0 million unsecured facility and $25.0 million secured facility, including related accrued interest through the date of repayment of approximately $5.9 million. Additionally, $50.0 million of net proceeds were used to repay outstanding revolving loan indebtedness under the Company 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 628,667.20 for 1 stock split of CVR s common stock and the mergers of two newly formed direct subsidiaries of CVR into Coffeyville Refining & Marketing Holdings, Inc. (Refining Holdco) and Coffeyville Nitrogen Fertilizers, Inc. (CNF). Concurrent with the merger of the subsidiaries and in accordance with a previously executed agreement, the Company s chief executive officer received 247,471 shares of CVR common stock in exchange for shares that he owned of Refining Holdco and CNF. The shares were fully vested and were exchanged at fair market value.

The Company also issued 27,100 shares of common stock to its employees on October 24, 2007 in connection with the initial public offering. 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 noted below.

**CVR ENERGY, INC. AND SUBSIDIARIES**
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**(unaudited)**

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 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 will vest on October 24, 2008, one-third will vest on October 24, 2009, and the final one-third will vest on October 24, 2010.

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 will vest over a three year service period. Fair value was measured using an option-pricing model at the date of grant.

***Nitrogen Fertilizer Limited Partnership***

In conjunction with the consummation of CVR s initial public offering, CVR transferred Coffeyville Resources Nitrogen Fertilizer, LLC (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 Coffeyville Acquisition LLC III (CALLC III), an entity owned by CVR s controlling stockholders and senior management at fair market value. The board of directors of CVR determined, after consultation with management, that the fair market value of the managing general partner interest was $10.6 million. This interest has been reflected as minority interest in the Consolidated Balance Sheet.

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. 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 in the Partnership s initial public offering. The Partnership and its subsidiaries are currently guarantors under the credit facility of Coffeyville Resources, LLC (CRLLC), a wholly-owned subsidiary of CVR.

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

**CVR ENERGY, INC. AND SUBSIDIARIES**
**NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**
**MARCH 31, 2008**
**(unaudited)**

has joint management rights regarding the appointment, termination, and compensation of the chief executive officer and chief financial officer of the managing general partner, has the right to designate two members of the board of directors of the managing general partner, and has joint management rights regarding specified major business decisions relating to the Partnership. CVR, the Partnership, the managing general partner and various of their subsidiaries also entered into a number of agreements to regulate certain business relations between the parties.

At March 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.

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

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

5,250,000 common units representing limited partner interests, all of which the Partnership will sell in the initial public offering;

18,750,000 GP units representing special general partner interests, all of which will be held by the Partnership s special general partner;

18,000,000 subordinated GP units representing special general partner interests, all of which will be held by the Partnership s special general partner; and

a managing general partner interest, which is not entitled to any distributions, which is held by the Partnership s managing general partner, and incentive distribution rights representing limited partner interests, all of which will be held by the Partnership s managing general partner.

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

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

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

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**(unaudited)**

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

During the subordination period, the subordinated units will not be entitled to receive any distributions until the common units and GP units have received the minimum quarterly distribution of $0.375 per unit plus any arrearages from prior quarters. The subordination period begins on the closing date of the Partnership s initial public offering and will end once the Partnership meets the financial tests in the partnership agreement. When the subordination period ends, all subordinated units will convert into GP units or common units on a one-for-one basis, and the common units and GP units will no longer be entitled to arrearages.

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

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

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

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

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

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**CVR ENERGY, INC. AND SUBSIDIARIES**
**NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**
**MARCH 31, 2008**
**(unaudited)**

***Basis of Presentation***

The accompanying unaudited condensed consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles (GAAP) and in accordance with the rules and regulations of the SEC. The 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. Certain information and footnotes required for the complete financial statements under GAAP have been condensed or omitted pursuant to such rules and regulations. These unaudited condensed consolidated financial statements should be read in conjunction with the December 31, 2007 audited consolidated financial statements and notes thereto included in CVR s Annual Report on Form 10-K/A for the year ended December 31, 2007.

In the opinion of the Company s management, the accompanying unaudited condensed consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments) that are necessary to fairly present the financial position of the Company as of March 31, 2008 and December 31, 2007, the results of operations for the three months ended March 31, 2008 and 2007, and the cash flows for the three months ended March 31, 2008 and 2007.

Results of operations and cash flows for the interim periods presented are not necessarily indicative of the results that will be realized for the year ending December 31, 2008 or any other interim period. The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In connection with CVR s initial public offering, $0.5 million of deferred offering costs for the three months ended March 31, 2007 were previously presented in operating activities in the interim financial statements. Such amounts have now been reflected as financing activities for the three months ended March 31, 2007 in the accompanying Consolidated Statements of Cash Flows. The impact on the prior financial statements of this revision is not considered material.

**(2) Recent Accounting Pronouncements**

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement on Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price). The standard s provisions for financial assets and financial liabilities, which became effective January 1, 2008, had no material impact on the Company s financial position or results of operations. At March 31, 2008, the only financial assets and financial liabilities that are measured at fair value on a recurring basis are the Company s derivative instruments. See Note 14, Fair Value Measurements.

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. Under this standard, an entity is required to provide additional information that will assist investors and other users of financial information to more easily understand the effect of the Company s choice to use fair value on its earnings. Further, the entity is required to display the fair value of those assets and liabilities for which the Company has chosen to use fair value on the face of the balance sheet. This standard does not eliminate the disclosure requirements about fair value measurements included in SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*. The provisions of SFAS 159 were effective for CVR as of January 1, 2008. The Company did not elect the fair value option under this standard upon adoption. Therefore, the adoption of SFAS 159 did not impact the Company s consolidated financial statements as of the quarter ended March 31, 2008.



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

In December 2007, the FASB issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements an amendment of ARB No. 51*. SFAS 160 establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 must be applied prospectively. SFAS 160 is effective for CVR beginning January 1, 2009. The Company is currently evaluating the potential impact of the adoption of SFAS 160 on its consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement will change the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, net earnings, and cash flows. The Company will be required to adopt this statement as of January 1, 2009. The adoption of SFAS 161 is not expected to have a material impact on the Company s consolidated financial statements.

**(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 had 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 connection with the restructuring of the Company related to the Partnership, CALLC III issued non-voting override units to certain management members of CALLC III.

CVR, CALLC, CALLC II and CALLC III account for share-based compensation in accordance with SFAS No. 123(R), *Share-Based Payments* and EITF 00-12, *Accounting by an Investor for Stock-Based Compensation Granted to Employees of an Equity Method Investee*. CVR has recorded non-cash share-based compensation 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 96-18, *Accounting for Equity Investments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with*

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*Selling Goods or Services*, which requires remeasurement at each reporting period. At March 31, 2008, CVR s common stock closing price was utilized to determine the fair value of the override units of CALLC and CALLC II. The estimated fair value per unit reflects a ratio of override units to shares of common stock. The estimated fair value of the override units of CALLC III has been determined using a binomial and 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.

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

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

In June 2005, CALLC issued 919,630 non-voting override operating units to certain management members holding common units of CALLC. There were no required capital contributions for the override operating units.

In accordance with SFAS 123(R), *Share Based Compensation*, using the Monte Carlo method of valuation, the estimated fair value of the override operating units on June 24, 2005 was $3,605,000. Pursuant to the forfeiture schedule described below, CVR recognized compensation expense over the service period for each separate portion of the award for which the forfeiture restriction lapsed as if the award was, in substance, multiple awards. Compensation expense of $(558,000) and $285,000 was recognized for the three months ending March 31, 2008 and 2007, respectively.

In connection with the split of CALLC into two entities on October 16, 2007, management s equity interest in CALLC was split so that half of management s equity interest is in CALLC and half is in CALLC II. The restructuring resulted in a modification of the existing awards under SFAS 123(R). However, because the fair value of the modified award equaled the fair value of the original award before the modification, there was no accounting consequence as a result of the modification. However, due to the restructuring, the employees of CVR and the Partnership no longer hold share-based awards in a parent company. Due to the change in status of the employees related to the awards, CVR recognized compensation expense for the newly measured cost attributable to the remaining vesting (service) period prospectively from the date of the change in status.

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 | $5.16 per share | N/A |
| March 31, 2008 CVR closing stock price | N/A | $23.03 |
| March 31, 2008 estimated fair value | N/A | $47.88 per share |
| Marketability and minority interest discounts | 24% discount | 15% discount |
| Volatility | 37% | N/A |

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

On December 28, 2006, CALLC issued 72,492 additional non-voting override operating units to a management member who held common units of CALLC. There were no required capital contributions for the override operating units.

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In accordance with SFAS 123(R), a combination of a binomial model and a probability-weighted expected return method which utilized CVR s cash flow projections resulted in an estimated fair value of the override operating units on December 28, 2006 of $473,000. Management believed that this method was preferable for the valuation of the override units as it allowed a better integration of the cash flows with other inputs, including the timing of potential exit events that impact the estimated fair value of the override units. These override operating units are being accounted for the same as the override operating units with the adjusted benchmark value of $11.31 per unit. In accordance with the accounting method noted above and pursuant to the forfeiture schedule described below, CVR recognized compensation expense of $6,000 and $100,000 for the periods ending March 31, 2008 and 2007, respectively.

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 |
| March 31, 2008 CVR closing stock price | N/A | $23.03 |
| March 31, 2008 estimated fair value | N/A | $28.68 per share |
| Marketability and minority interest discounts | 20% discount | 15% discount |
| Volatility | 41% | N/A |

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

| Minimum Period Held | Forfeiture Rate |
|---|---|
| 2 years | 75% |
| 3 years | 50% |
| 4 years | 25% |
| 5 years | 0% |

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

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

In June 2005, CALLC issued 1,839,265 non-voting override value units to certain management members who held common units of CALLC. There were no required capital contributions for the 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. For the override value units, CVR is recognizing compensation expense ratably over the implied service period of 6 years. These override value units are being accounted for the same as the override operating units with an adjusted benchmark value of $11.31 per unit. In

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accordance with the accounting method noted above, CVR recognized compensation expense of $533,000 and $169,000 for the three months ending March 31, 2008 and 2007, respectively.

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 |
| March 31, 2008 CVR closing stock price | N/A | $23.03 |
| March 31, 2008 estimated fair value | N/A | $47.88 per share |
| Marketability and minority interest discounts | 24% discount | 15% discount |
| Volatility | 37% | N/A |

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

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

In accordance with SFAS 123(R), a combination of a binomial model and a probability-weighted expected return method which utilized CVR s cash flow projections resulted in an estimated fair value of the override value units on December 28, 2006 of $945,000. Management believed that this method was preferable for the valuation of the override units as it allowed a better integration of the cash flows with other inputs, including the timing of potential exit events that impacted the estimated fair value of the override units. These override value units are being accounted for the same as the override operating units with the adjusted benchmark value of $11.31 per unit. In accordance with the accounting method noted above, CVR recognized compensation expense of $91,000, and $52,000 for the three months ending March 31, 2008 and 2007, respectively.

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 |
| March 31, 2008 CVR closing stock price | N/A | $23.03 |
| March 31, 2008 estimated fair value | N/A | $28.68 per share |
| Marketability and minority interest discounts | 20% discount | 15% discount |
| Volatility | 41% | N/A |

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 with the number of units subject to forfeiture reducing as follows:

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| Minimum period held | Subject to forfeiture percentage |
|---|---|
| 2 years | 75% |
| 3 years | 50% |
| 4 years | 25% |
| 5 years | 0% |

At March 31, 2008, assuming no change in the estimated fair value at March 31, 2008, there was approximately $59.2 million of unrecognized compensation expense related to non-voting override units. This is expected to be recognized over a remaining period of four years as follows (in thousands):

| | Override Operating Units | Override Value Units |
|---|---|---|
| Nine months ending December 31, 2008 | $ 4,927 | $ 11,688 |
| Year ending December 31, 2009 | 3,762 | 15,585 |
| Year ending December 31, 2010 | 1,120 | 15,584 |
| Year ending December 31, 2011 | | 6,569 |
| | $ 9,809 | $ 49,426 |

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

In October 2007, CALLC III issued 138,281 non-voting override units to certain management members who held common units of CALLC III. There were no required capital contributions for the override units.

In accordance with SFAS 123(R), *Share Based Compensation*, using a binomial and a probability-weighted expected return method which utilized CALLC III s cash flow projections, the estimated fair value of the operating units at March 31, 2008 was immaterial. CVR recognizes compensation costs for this plan based on the fair value of the awards at the end of each reporting period in accordance with EITF 00-12 using the guidance in EITF 96-18. In accordance with EITF 00-12, as a noncontributing investor, CVR also recognized income equal to the amount that its interest in the Partnership s net book value has increased (that is, its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation costs. This amount equaled the compensation expense recognized for these awards for the three months ended March 31, 2008. Pursuant to the forfeiture schedule reflected above, CVR recognized compensation expense over this service period for each portion of the award for which the forfeiture restriction has lapsed. As of March 31, 2008, these override units are fully vested.

Significant assumptions used in the valuation were as follows:

| | |
|---|---|
| Estimated forfeiture rate | None |
| March 31, 2008 estimated fair value | $0.004 per share |
| Marketability and minority interest discount | 15% discount |
| Volatility | 36.2% |

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***642,219 override units with a benchmark amount of $10***

On February 15, 2008, CALLC III issued 642,219 non-voting override units to certain management members of CALLC III. There were no required capital contributions for the override units.

In accordance with SFAS 123(R), *Share Based Compensation,* using a binomial and a probability-weighted expected return method which utilized CALLC III s cash flows projections, the estimated fair value of the operating units at March 31, 2008 was immaterial. CVR recognizes compensation costs for this plan based on the fair value of the awards at the end of each reporting period in accordance with EITF 00-12 using the guidance in EITF 96-18. In accordance with EITF 00-12, as a noncontributing investor, CVR also recognized income equal to the amount that its interest in the investee s net book value has increased (that is, its percentage share of the contributed capital recognized by the investee) as a result of the disproportionate funding of the compensation costs. CVR recognized compensation expense of $600 for the three months ended March 31, 2008. Pursuant to the forfeiture schedule of the amended and restated partnership agreement of CALLC III, CVR recognized compensation expense over this service period for each portion of the award for which the forfeiture restriction has lapsed. Of the 642,219 units issued, 109,720 were immediately vested upon issuance and the remaining units are subject to the forfeiture schedule.

Significant assumptions used in the valuation were as follows:

| | |
|---|---|
| Estimated forfeiture rate | None |
| Derived Service Period | Based on forfeiture schedule |
| March 31, 2008 estimated fair value | $0.004 per share |
| Marketability and minority interest discount | 15% discount |
| Volatility | 36.2% |

***Phantom Unit Appreciation Plan***

The Company, through a wholly-owned subsidiary, has a Phantom Unit Appreciation Plan whereby directors, employees, and service providers may be awarded phantom points at the discretion of the board of directors or the compensation committee. Holders of service phantom points have rights to receive distributions when holders of override operating units receive distributions. Holders of performance phantom points have rights to receive distributions when holders of override value units receive distributions. There are no other rights or guarantees, and the plan expires on July 25, 2015 or at the discretion of the compensation committee of the board of directors. As of March 31, 2008, the issued Profits Interest (combined phantom plan 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), using the March 31, 2008 CVR stock closing price to determine the Company s equity value, through an independent valuation process, the service phantom interest and performance phantom interest were both valued at $47.88 per point. CVR has recorded approximately $28,670,000 and $29,217,000 in personnel accruals as of March 31, 2008 and December 31, 2007, respectively. Compensation expense for the three month periods ending March 31, 2008 and 2007 related to the Phantom Unit Appreciation Plan was $(547,000) and $3,136,000, respectively.

At March 31, 2008, assuming no change in the estimated fair value at March 31, 2008, there was approximately $20.6 million of unrecognized compensation expense related to the Phantom Unit Appreciation Plan. This is expected to be recognized over a remaining period of four years.

***Long Term Incentive Plan***

CVR has a Long Term Incentive Plan. There were no awards granted under this plan in the first quarter of 2008.

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On October 24, 2007, 17,500 shares of non-vested common stock having a fair 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 on 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 will be amortized over the respective vesting periods. One-third will vest on October 24, 2008, 2009 and 2010, respectively.

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. Options to purchase 8,600 shares of common stock at an exercise price of $24.73 per share were granted to outside directors on December 21, 3007.

During the quarter there were no issuances, forfeitures or vesting of stock options or non-vested shares.

As of March 31, 2008, there was approximately $0.2 million of total unrecognized compensation cost related to non-vested shares to be recognized over a weighted-average period of approximately one year. Compensation expense recorded for the three month periods ending March 31, 2008 and 2007 related to the non-vested stock was $56,000 and $0, respectively. Compensation expense for the three month periods ending March 31, 2008 and 2007 related to stock options was $36,000 and $0, respectively.

**(4) 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.

Inventories consisted of the following (in thousands):

| | March 31, 2008 | December 31, 2007 |
|---|---|---|
| Finished goods | $ 123,814 | $ 109,394 |
| Raw materials and catalysts | 123,042 | 92,104 |
| In-process inventories | 17,045 | 29,817 |
| Parts and supplies | 24,514 | 23,340 |
| | $ 288,415 | $ 254,655 |

**(5) Property, Plant, and Equipment**

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

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| | March 31, 2008 | December 31, 2007 |
|---|---|---|
| Land and improvements | $ 13,170 | $ 13,058 |
| Buildings | 19,351 | 17,541 |
| Machinery and equipment | 1,277,292 | 1,108,858 |
| Automotive equipment | 5,752 | 5,171 |
| Furniture and fixtures | 6,420 | 6,304 |
| Leasehold improvements | 929 | 929 |
| Construction in progress | 30,859 | 182,046 |
| | 1,353,773 | 1,333,907 |
| Accumulated depreciation | 161,231 | 141,733 |
| | $ 1,192,542 | $ 1,192,174 |

Capitalized interest recognized as a reduction in interest expense for the periods ended March 31, 2008, and March 31, 2007 totaled approximately $1,118,000 and $4,079,000, respectively.

**(6) 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. The Coffeyville nitrogen fertilizer plant last completed a major scheduled turnaround in the third quarter of 2006 and is scheduled to complete a turnaround in the fourth quarter of 2008. The Coffeyville refinery started a major scheduled turnaround in February 2007 with completion in April 2007. Costs of $66,003,000 associated with the 2007 refinery turnaround were included in direct operating expenses (exclusive of depreciation and amortization) for the three months ending March 31, 2007.

**(7) 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 $600,000 and $619,000 for the three months ended March 31, 2008 and March 31, 2007, respectively.

Direct operating expenses (exclusive of depreciation and amortization) includes direct costs of labor, maintenance and services, energy and utility costs, environmental compliance costs as well as chemicals and catalysts and other direct operating expenses. Direct operating expenses excludes depreciation and amortization of $18,703,000 and $13,530,000 for the three months ended March 31, 2008 and March 31, 2007, respectively.

Selling, general and administrative expenses (exclusive of depreciation and amortization) consists primarily of legal expenses, treasury, accounting, marketing, human resources and maintaining the corporate offices in Texas and Kansas. Selling, general and administrative expenses excludes depreciation and amortization of $332,000 and $86,000 for the three months ended March 31, 2008 and March 31, 2007, respectively.

**(8) Note Payable and Capital Lease Obligations**

The Company entered into an insurance premium finance agreement with Cananwill, Inc. in July 2007 to finance the purchase of its property, liability, cargo and terrorism policies. The original balance of the note was $7.6 million and required repayment in nine equal installments with final payment due in April 2008. The balance due was paid in full in April 2008. As of March 31, 2008 and December 31, 2007, $0.8 and $3.4 million related to this

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insurance premium finance agreement was included in note payable and capital lease obligations on the Consolidated Balance Sheet, respectively.

The Company entered into two capital leases in 2007 to lease platinum required in the manufacturing of a new catalyst. The recorded lease obligations fluctuate with the platinum market price. The leases will terminate on the date an equal amount of platinum is returned to each lessor, with the difference to be paid in cash. One lease was settled and terminated in January 2008. At March 31, 2008 and December 31, 2007 the lease obligations were recorded at approximately $10.4 million and $8.2 million on the Consolidated Balance Sheets, respectively.

**(9) Flood and Insurance Related Matters**

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

Management continues to work closely with the Company s insurance carriers and claims adjusters to ascertain the full amount of insurance proceeds due to the Company as a result of the damages and losses. At March 31, 2008, total accounts receivable from insurance was $85.7 million. 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. Management believes the recovery of the receivable from the insurance carriers is probable. Approximately $11.4 million of the receivable recorded at March 31, 2008 relates to the crude oil discharge and the remaining $74.3 million relates to the flood damage to the Company s facilities. While management believes that the Company s property insurance should cover substantially all of the estimated total physical damage to the property, the Company s insurance carriers have cited potential coverage limitations and defenses that might preclude such a result.

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

The Company has recorded pretax costs in total of approximately $47.3 million associated with the flood and related crude oil discharge as discussed in Note 12, Commitments and Contingent Liabilities, including $5.8 million of net pretax costs in the first quarter of 2008. These amounts are net of anticipated insurance recoveries of $107.2 million including $1.8 million of recoveries for the first quarter of 2008. These costs are reported in Net costs associated with flood in the Consolidated Statements of Operations.

Total gross costs recorded due to the flood and related oil discharge that were included in the Consolidated Statements of Operations for the three months ended March 31, 2008 were $7.6 million. Of these gross costs for the three month period ended March 31, 2008, $3.8 million were associated with repair and other matters as a result of the flood damage to the Company s facilities. Included in this cost was $ 0.3 million of professional fees and $3.5 million for other repair and related costs. There were also $3.8 million of costs recorded for the three month period ended March 31, 2008 related to the third party and property damage remediation as a result of the crude oil discharge.

Below is a summary of the gross cost and reconciliation of the insurance receivable (in millions):

| | Total Costs | For the Three Months Ended March 31, 2008 |
|---|---|---|
| Total gross costs incurred | $ 154.5 | $ 7.6 |
| Total insurance receivable | (107.2) | (1.8) |
| Net costs associated with the flood | $ 47.3 | $ 5.8 |

| | Receivable Reconciliation |
|---|---|
| Total insurance receivable | $ 107.2 |
| Less insurance proceeds received | (21.5) |
| Insurance receivable | $ 85.7 |

The Company anticipates that approximately $2.1 million in additional third party costs related to the repair of flood damaged property will be recorded in future periods. Although the Company believes that it will recover

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substantial sums under its insurance policies, the Company is not sure of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of the Company s claims. The difference between what the Company ultimately receives under its insurance policies compared to what has been recorded and described above could be material to the consolidated financial statements.

In 2007, the Company had received insurance proceeds of $10.0 million under its property insurance policy and $10.0 million under its environmental policies related to recovery of certain costs associated with the crude oil discharge. In the first quarter of 2008, the Company received $1.5 million under its Builder s Risk Insurance Policy. See Note 12, Commitments and Contingent Liabilities for additional information regarding environmental and other contingencies relating to the crude oil discharge that occurred on July 1, 2007.

**(10) Income Taxes**

The Company adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertain Tax Positions an interpretation of FASB No. 109* (FIN 48) on January 1, 2007. The adoption of FIN 48 did not affect the Company s financial position or results of operations. The Company does not have any unrecognized tax benefits as of March 31, 2008.

The Company did not accrue or recognize any amounts for interest or penalties in its financial statements for the three months ended March 31, 2008. The Company will classify interest to be paid on an underpayment of income taxes and any related penalties as income tax expense if it is determined, in a subsequent period, that a tax position is not more likely than not of being sustained.

CVR and its subsidiaries file U.S. federal and various state income tax returns. The Company is currently under a U.S. federal income tax examination for its 2005 tax year. The Company has not been subject to any other U.S. federal, state or local income tax examinations by tax authorities for any tax year. The U.S. federal and state tax years subject to examination are 2004 to 2007. As of March 31, 2008, no taxing authority has proposed any adjustments to the Company s tax positions.

The Company s effective tax rates for the three months ended March 31, 2008 and 2007 were 23.6% and 23.4%, respectively, as compared to the federal statutory tax rate of 35%. The effective tax rate is lower than the statutory rate due to federal income tax credits available to small business refiners related to the production of ultra low sulfur diesel fuel and Kansas state incentives generated under the High Performance Incentive Program (HPIP).

**(11) Earnings (Loss) 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 Company and Basis of Presentation .

Earnings per share for the three months ended March 31, 2008 is calculated as noted below.

| | Earnings | Shares | Per Share |
|---|---|---|---|
| Basic earnings per share | $22,221,000 | 86,141,291 | $0.26 |
| Diluted earnings per share | $22,221,000 | 86,158,791 | $0.26 |

Outstanding stock options totaling 18,900 common shares were excluded from the diluted earnings per share calculation for the three months ended March 31, 2008 as they were antidilutive.

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The computation of basic and diluted loss per share for the quarter ended March 31, 2007 is calculated on a pro forma basis assuming the capital structure in place after the completion of the offering was in place for the entire period.

Pro forma loss per share for the three months ended March 31, 2007 is calculated as noted below. For the three months ended March 31, 2007, 17,500 non-vested shares of common stock and 18,900 common stock options have been excluded from the calculation of pro forma diluted earnings per share because the inclusion of such common stock equivalents in the number of weighted average shares outstanding would be anti-dilutive:

| | March 31, 2007 (Unaudited) |
|---|---|
| Net (loss) | $ (154,373,000) |
| Pro forma weighted average shares outstanding: | |
| Original CVR shares of common stock | 100 |
| Effect of 628,667.20 to 1 stock split | 62,866,620 |
| Issuance of shares of common stock to management in exchange for subsidiary shares | 247,471 |
| Issuance of shares of common stock to employees | 27,100 |
| Issuance of shares of common stock in the initial public offering | 23,000,000 |
| Basic weighted average shares outstanding | 86,141,291 |
| Dilutive securities issuance of non-vested shares of common stock to board of directors | |
| Diluted weighted average shares outstanding | 86,141,291 |
| Pro forma basic loss per share | $ (1.79) |
| Pro forma dilutive loss per share | $ (1.79) |

**(12) Commitments and Contingent Liabilities**

The minimum required payments for the Company s lease agreements and unconditional purchase obligations are as follows (in thousands):

| | Operating Leases | Unconditional Purchase Obligations |
|---|---|---|
| Nine months ending December 31, 2008 | $ 2,833 | $ 20,757 |
| Year ending December 31, 2009 | 3,266 | 28,229 |
| Year ending December 31, 2010 | 1,680 | 55,762 |
| Year ending December 31, 2011 | 948 | 53,939 |
| Year ending December 31, 2012 | 196 | 51,333 |
| Thereafter | 10 | 372,325 |
| | $ 8,933 | $ 582,345 |

The Company leases various equipment and real properties under long-term operating leases. For the three months ended March 31, 2008 and 2007, lease expense totaled $1,071,000 and $1,007,000, respectively. The lease

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agreements have various remaining terms. Some agreements are renewable, at the Company s option, for additional periods. It is expected, in the ordinary course of business, that leases will be renewed or replaced as they expire.

From time to time, the Company 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 lawsuits are recognized when the related costs are probable and can be reasonably estimated. 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 the Company s litigation matters is not expected to have a material adverse effect on the accompanying consolidated financial statements. There can be no assurance that management s 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. As a result of the crude oil discharge, two putative class action lawsuits (one federal and one state) were filed seeking unspecified damages with class certification under applicable law for all residents, domiciliaries and property owners of Coffeyville, Kansas who were impacted by the oil release.

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

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

As a result of the crude oil discharge that occurred on July 1, 2007, the Company entered into an administrative order on consent (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 is currently remediating the crude oil discharge and expects its primary remedial actions to continue through May 2008 with continuing minor activities for a period thereafter.

The Company engaged experts to assess and test the areas affected by the crude oil spill. The Company commenced a program on July 19, 2007 to purchase approximately 330 homes and other commercial properties in connection with the flood and the crude oil release. Total costs recorded to date are $13.4 million, which include costs incurred in 2007 of $13.1 million and costs for the three months ended March 31, 2008 of $0.3 million. Total costs recorded related to personal property claims were approximately $1.7 million, which were all recorded in 2007. Total costs recorded related to estimated commercial property to be purchased and associated claims were approximately $3.6 million, which were all recorded in 2007. The total amount of gross costs recorded for the three months ended March 31, 2008 related to the residential and commercial purchase and property claims program were approximately $0.3 million. As the crude oil spill took place in the second and third quarter of 2007, no costs associated with the spill were incurred in the first quarter of 2007.

As of March 31, 2008, the total costs recorded for obligations other than the purchase of homes, commercial properties and related personal property claims approximated $30.0 million. The Company has recorded as of March 31, 2008 total costs (net of anticipated insurance recoveries recorded of $21.4 million) associated with remediation and third party property damage claims resolution of approximately $27.3 million. The Company has not estimated or accrued for, because management does not believe it is probable that there will be

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any potential fines, penalties or claims that may be imposed or brought by regulatory authorities or possible additional damages arising from class action lawsuits related to the flood.

It is difficult to estimate the ultimate cost of environmental remediation resulting from the crude oil discharge or the cost of third party property damage that the Company will ultimately be required to pay. The costs and damages that the Company will ultimately pay may be greater than the amounts described and projected above. Such excess costs and damages could be material to the consolidated financial statements.

The Company is seeking insurance coverage for this release and for the ultimate costs for remediation, property damage claims, cleanup, resolution of class action lawsuits, and other claims brought by regulatory authorities. Although the Company believes that it will recover substantial sums under its environmental and liability insurance policies, the Company is not sure of the ultimate amount or timing of such recovery because of the difficulty inherent in projecting the ultimate resolution of the Company s claims. The difference between what the Company receives under its insurance policies compared to what has been recorded and described above could be material to the consolidated financial statements. The Company received $10.0 million of insurance proceeds under its environmental insurance policy in 2007.

***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 the Company 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.

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 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 March 31, 2008 and December 31, 2007, environmental accruals of $7,713,000 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 $2,789,000 and $2,802,000, respectively, included in other current liabilities. The Company s accruals were determined based on an estimate of payment costs through 2033, which scope of remediation was arranged with the EPA and are discounted at the appropriate risk free rates at March 31, 2008 and December 31, 2007, respectively. The accruals include estimated closure and post-closure costs of $1,580,000 and $1,549,000 for two landfills at March 31, 2008 and December 31, 2007, respectively. The estimated future payments for these required obligations are as follows (in thousands):

| | **Amount** |
|---|---|
| Nine months ending December 31, 2008 | 2,617 |
| Year ending December 31, 2009 | 687 |
| Year ending December 31, 2010 | 1,556 |
| Year ending December 31, 2011 | 313 |
| Year ending December 31, 2012 | 313 |
| Thereafter | 3,282 |

| | | |
|---|---|---|
| Undiscounted total | | 8,768 |
| Less amounts representing interest at 3.13% | | 1,055 |
| Accrued environmental liabilities at March 31, 2008 | $ | 7,713 |

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

The EPA has issued regulations intended to limit amounts of sulfur in diesel and gasoline. The EPA has granted the Company a petition for a technical hardship waiver with respect to the date for compliance in meeting the sulfur-lowering standards. CVR spent approximately $17 million in 2007, $79 million in 2006 and $27 million in 2005 to comply with the low-sulfur rules. CVR has spent $2 million in the first three months of 2008 and based on information currently available, anticipates spending approximately $17 million in the last nine months of 2008 and $26 million in 2009 to comply with the low-sulfur rules. The entire amounts are expected to be capitalized.

Environmental expenditures are capitalized when such expenditures are expected to result in future economic benefits. For the three month periods ended March 31, 2008 and 2007, capital expenditures were $15,473,000 and $50,687,000, 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 Company s business, financial condition, or results of operations.

**(13) Derivative Financial Instruments**

Loss on derivatives consisted of the following (in thousands):

| | Three Months Ended March 31, | |
|---|---|---|
| | **2008** | **2007** |
| Realized loss on swap agreements | $ (21,516) | $ (8,534) |
| Unrealized loss on swap agreements | (13,907) | (119,704) |
| Realized loss on other agreements | (7,993) | (2,763) |
| Unrealized gain (loss) on other agreements | 1,157 | (5,332) |
| Realized gain on interest rate swap agreements | 522 | 1,241 |
| Unrealized loss on interest rate swap agreements | (6,134) | (1,867) |
| Total loss on derivatives | $ (47,871) | $ (136,959) |

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, CVR may enter into various derivative transactions. In addition, CALLC, 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*. SFAS 133 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

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change in fair value and periodic settlements of these derivative instruments are classified as loss on derivatives, net in the Consolidated Statements of Operations.

At March 31, 2008, 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 15, Related Party Transactions ). The swap agreements were originally executed by CALLC on June 16, 2005 and were required under the terms of the Company s long-term debt agreements. The notional quantities on the date of execution were 100,911,000 barrels of crude oil, 1,889,459,250 gallons of heating oil and 2,348,802,750 gallons of unleaded gasoline. 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 March 31, 2008 the notional open amounts under the swap agreements were 36,190,000 barrels of crude oil, 759,990,000 gallons of heating oil and 759,990,000 gallons of unleaded gasoline. These positions resulted in unrealized losses for the three months ended March 31, 2008 and 2007 of $13,907,000 and $119,704,000, respectively. The Petroleum Segment recorded $21,516,000 and $8,534,000 in realized losses on these swap agreements for the three month periods ended March 31, 2008 and 2007, respectively.

The Petroleum Segment also recorded mark-to-market net losses, in loss on derivatives, net exclusive of the swap agreements described above and the interest rate swaps described in the following paragraph, of $6,836,000 and $8,095,000, for the three month periods ended March 31, 2008 and 2007, respectively. All of the activity related to the commodity derivative contracts is reported in the Petroleum Segment.

At March 31, 2008, CRLLC held derivative contracts known as interest rate swap agreements that converted CRLLC s floating-rate bank debt into 4.195% fixed-rate debt on a notional amount of $325,000,000. Half of the agreements are held with a related party (as described in Note 15, Related Party Transactions ), and the other half are held with a financial institution that is a lender under CRLLC s long-term debt agreements. The swap agreements carry the following terms:

| Period covered | Notional amount | Fixed interest rate |
|---|---|---|
| June 30, 2007 to March 31, 2008 | 325 million | 4.195% |
| March 31, 2008 to March 30, 2009 | 250 million | 4.195% |
| March 31, 2009 to March 30, 2010 | 180 million | 4.195% |
| March 31, 2010 to June 29, 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 losses on derivatives and quarterly settlements were $5,612,000 and $626,000 for the three month periods ended March 31, 2008 and 2007, respectively.

**(14) 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.

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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 to the Condensed Consolidated Financial Statements. As of March 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 March 31, 2008 (in thousands):

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash Flow Swap | | $(13,907) | | $(13,907) |
| Interest Rate Swap | | (6,134) | | (6,134) |
| Other Derivative Agreements | | 1,157 | | 1,157 |

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.

**(15) Related Party Transactions**

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

On June 24, 2005, CALLC entered into management services agreements with each of GS and Kelso pursuant to which GS and Kelso agreed to provide CALLC with managerial and advisory services. In consideration for these services, an annual fee of $1.0 million was paid to each of GS and Kelso, plus reimbursement for any out-of-pocket expenses. The agreements terminated upon consummation of CVR s initial public offering on October 26, 2007. Relating to the agreements, $0 and $538,000 were expensed in selling, general, and administrative expenses (exclusive of depreciation and amortization) for the three months ended March 31, 2008 and March 31, 2007, respectively. The Company paid a one-time fee of $5.0 million to each of GS and Kelso by reason of the termination of the agreements on October 26, 2007.

CALLC entered into certain crude oil, heating oil and gasoline swap agreements with a subsidiary of GS. Additional swap agreements with this subsidiary of GS were entered into on June 16, 2005, with an expiration date of June 30, 2010 (as described in Note 13, Derivative Financial Instruments ). These agreements were assigned to Coffeyville Resources LLC, a subsidiary of CVR. Losses totaling $35,423,000 and $128,238,000 were recognized related to these swap agreements for the three months ended March 31, 2008 and 2007, respectively, and are

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reflected in loss on derivatives, net in the Consolidated Statements of Operations. In addition, the Consolidated Balance Sheet at March 31, 2008 and December 31, 2007 includes liabilities of $294,984,000 and $262,415,000, respectively, included in current payable to swap counterparty and $76,411,000 and $88,230,000, respectively, included in long-term payable to swap counterparty.

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

As a result of the flood and the related temporary cessation of business operations, the Company entered into a subsequent letter agreement on July 11, 2007 in which the GS subsidiary agreed to defer an additional $43.7 million of the balance owed for the period ending June 30, 2007. This deferral was entered into on the conditions that each of GS and Kelso agreed to guarantee one half of the payment and that interest accrued on the $43.7 million from July 9, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On July 26, 2007, the Company entered into a letter agreement in which the GS subsidiary agreed to defer to September 7, 2007 both the $45.0 million payment due August 7, 2007 along with accrued interest and the $43.7 million payment due July 25, 2007 with the related accrued interest. These payments were deferred on the conditions that GS and Kelso each agreed to guarantee one half of the payments. Additionally, interest accrues on the amount from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, the Company entered into an additional letter agreement in which the GS subsidiary agreed to further defer both deferred payment amounts and the related accrued interest with payment being due on January 31, 2008. Additionally, it was further agreed that the $35 million payment to settle hedged volumes through August 15, 2007 would be deferred with payment being due on January 31, 2008. Interest accrues on all deferral amounts through the payment due date at LIBOR plus 1.50%. GS and Kelso have each agreed to guarantee one half of all payment deferrals. The GS subsidiary further agreed to defer these payment amounts to August 31, 2008 if the Company closed an initial public offering prior to January 31, 2008. Due to the consummation of the initial public offering on October 26, 2007, these payment amounts are now deferred until August 31, 2008; however, the company is required to use 37.5% of its consolidated excess cash flow for any quarter after January 31, 2008 to prepay the deferral amounts. As of March 31, 2008 the Company was not required to pay any portion of the deferred amount.

These deferred payment amounts are included in the Consolidated Balance Sheet at March 31, 2008 in current payable to swap counterparty. The deferred balance owed to GS, excluding accrued interest payable, totalled $123.7 million at March 31, 2008. Approximately $4,874,000 of accrued interest payable related to the deferred payments is included in other current liabilities at March 31, 2008.

On June 30, 2005, CALLC entered into three interest-rate swap agreements with the same subsidiary of GS (as described in Note 13, Derivative Financial Instruments ). Losses totaling $2,813,000 and $313,000 were recognized related to these swap agreements for the three months ended March 31, 2008 and 2007, respectively, and are reflected in loss on derivatives, net in the Consolidated Statements of Operations. In addition, the Consolidated Balance Sheet at March 31, 2008 and December 31, 2007 includes $1,778,000 and $371,000, respectively, in other current liabilities and $2,223,000 and $557,000, respectively, in other long-term liabilities related to the same agreements.

Effective December 30, 2005, the Company entered into a crude oil supply agreement with a subsidiary of GS (Supplier). Under the agreement, the parties agreed to negotiate the cost of each barrel of crude oil to be purchased from a third party, and CVR agreed to pay Supplier a fixed supply service fee per barrel over the negotiated cost of each barrel of crude purchased. The cost is adjusted further using a spread adjustment calculation based on the time period the crude oil is estimated to be delivered to the refinery, other market conditions, and other factors deemed appropriate. The initial term of the agreement was to December 31, 2006. CVR and Supplier agreed to extend

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the term of the supply agreement for an additional 12 month period, from January 1, 2007 through December 31, 2007, and in connection with the extension amended certain terms and conditions of the supply agreement. On December 31, 2007, CVR and supplier entered into an amended and restated crude oil supply agreement. The terms of the agreement remained substantially the same. $241,000 and $360,000 were recorded on the consolidated balance sheet at March 31, 2008 and December 31, 2007, respectively, in prepaid expenses and other current assets for prepayment of crude oil. In addition, $62,039,000 and $43,773,000 were recorded in inventory and $27,909,000 and $42,666,000 were recorded in accounts payable at March 31, 2008 and December 31, 2007, respectively. Expenses associated with this agreement, included in cost of product sold (exclusive of depreciation and amortization) for the three month period ended March 31, 2008 and 2007 totaled $766,213,000 and $176,307,000, respectively. Interest expense associated with this agreement for the three month period ended March 31, 2008 and 2007 totaled $14,000 and $(1,029,000), respectively.

As a result of the refinery turnaround in early 2007, CVR needed to delay the processing of quantities of crude oil that it purchased from various small independent producers. In order to facilitate this anticipated delay, CVR entered into a purchase, storage and sale agreement for gathered crude oil, dated March 20, 2007, with J. Aron, a subsidiary of GS. Pursuant to the terms of the agreement, J. Aron agreed to purchase gathered crude oil from CVR, store the gathered crude oil and sell CVR the gathered crude oil on a forward basis.

**(16) 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.

***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 priced 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 $2,806,000 and $580,000 for the three months ended March 31, 2008 and 2007, respectively.

Intercompany cost of product sold (exclusive of depreciation and amortization) for the hydrogen sales described below under Nitrogen Fertilizer was $5,291,000 and $2,829,000 for the three months ended March 31, 2008 and 2007, respectively.

***Nitrogen Fertilizer***

The principal product of the Nitrogen Fertilizer Segment is nitrogen fertilizer. Intercompany cost of product sold (exclusive of depreciation and amortization) for the coke transfer described above was $2,545,000 and $850,000 for the three months ended March 31, 2008 and 2007, respectively.

Beginning in 2008, the Nitrogen Fertilizer Segment made a change as to the classification of intercompany hydrogen sales to the Petroleum Segment. In 2008, these amounts are 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 quarters ended March 31, 2008 and 2007, the net sales generated from intercompany hydrogen sales were $5,291,000 and $2,829,000, respectively. As noted above, the net sales of $2,829,000 were included as a reduction to the cost of product sold (exclusive of depreciation and amortization) for 2007. As these intercompany sales are eliminated, there is no financial statement impact on the consolidated financial statements.

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***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.

| | Three Months Ended March 31, (in thousands) | |
|---|---|---|
| | **2008** | **2007** |
| Net sales | | |
| Petroleum | $ 1,168,500 | $ 352,488 |
| Nitrogen Fertilizer | 62,600 | 38,575 |
| Intersegment eliminations | (8,097) | (580) |
| Total | $ 1,223,003 | $ 390,483 |
| Cost of product sold (exclusive of depreciation and amortization) | | |
| Petroleum | $ 1,035,085 | $ 298,460 |
| Nitrogen Fertilizer | 8,945 | 6,060 |
| Intersegment eliminations | (7,836) | (850) |
| Total | $ 1,036,194 | $ 303,670 |
| Direct operating expenses (exclusive of depreciation and amortization) | | |
| Petroleum | $ 40,290 | $ 96,674 |
| Nitrogen Fertilizer | 20,266 | 16,738 |
| Other | | |
| Total | $ 60,556 | $ 113,412 |
| Net costs associated with flood | | |
| Petroleum | $ 5,533 | $ |
| Nitrogen Fertilizer | (17) | |
| Other | 247 | |
| Total | $ 5,763 | $ |
| Depreciation and amortization | | |
| Petroleum | $ 14,877 | $ 9,794 |
| Nitrogen Fertilizer | 4,477 | 4,394 |
| Other | 281 | 47 |

| | | |
|---|---|---|
| Total | $ 19,635 | $ 14,235 |
| | | |
| Operating income (loss) | | |
| Petroleum | $ 63,618 | $ (63,468) |
| Nitrogen Fertilizer | 26,017 | 9,319 |
| Other | (2,277) | 165 |
| Total | $ 87,358 | $ (53,984) |
| | | |
| Capital expenditures | | |
| Petroleum | $ 22,541 | $ 106,501 |
| Nitrogen Fertilizer | 2,817 | 402 |
| Other | 798 | 460 |
| Total | $ 26,156 | $ 107,363 |

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| | Three Months Ended March 31, 2008 | Year Ended December 31, 2007 |
|---|---|---|
| Total assets | | |
| Petroleum | $ 1,352,961 | $ 1,277,124 |
| Nitrogen Fertilizer | 496,326 | 446,763 |
| Other | 74,304 | 144,469 |
| Total | $ 1,923,591 | $ 1,868,356 |
| Goodwill | | |
| Petroleum | $ 42,806 | $ 42,806 |
| Nitrogen Fertilizer | 40,969 | 40,969 |
| Other | | |
| Total | $ 83,775 | $ 83,775 |

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**Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations**

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes and with the statistical information and financial data appearing in this Quarterly Report on Form 10-Q for the three month period ended March 31, 2008 (Form 10-Q) as well as the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007. Results of operations for the three month period ended March 31, 2008 are not necessarily indicative of results to be attained for any other period.

**Forward-Looking Statements**

This Form 10-Q, including this 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 Form 10-Q, including this Management s Discussion and Analysis of Financial Condition and Results of Operations, 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 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 in our Annual Report on Form 10-K/A for the year ended December 31, 2007 and contained elsewhere in this Form 10-Q.

All forward-looking statements contained in this Form 10-Q 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 Form 10-Q, or to reflect the occurrence of unanticipated events.

**Company Overview**

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

We operate under two business segments: petroleum and nitrogen fertilizer. Our petroleum business includes a 113,500 bpd complex full coking medium sour crude refinery in Coffeyville, Kansas. In addition, supporting businesses include (1) a crude oil gathering system serving central Kansas, northern Oklahoma, and southwest Nebraska, (2) storage and terminal facilities for asphalt and refined fuels in Phillipsburg, Kansas, and (3) a rack marketing division supplying product through tanker trucks directly to customers located in close geographic proximity to Coffeyville and Phillipsburg and at throughput terminals on Magellan Midstream Partners L.P. s (Magellan) refined products distribution systems. In addition to rack sales (sales which are made at terminals into third party tanker trucks), we make bulk sales (sales through third party pipelines) into the mid-continent markets via Magellan and into Colorado and other destinations utilizing the product pipeline networks owned by Magellan, Enterprise Products Partners L.P. and NuStar Energy L.P. Our refinery is situated approximately 100 miles from Cushing, Oklahoma, one of the largest crude oil trading and storage hubs in the United States. 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.

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The nitrogen fertilizer segment consists of our interest in CVR Partners, LP, a limited partnership controlled by our affiliates, which operates a nitrogen fertilizer plant and the nitrogen fertilizer business. The nitrogen fertilizer business is the lowest cost producer and marketer of ammonia and UAN in North America, at current natural gas and pet coke prices. The fertilizer plant is the only commercial facility in North America utilizing a coke gasification process to produce nitrogen fertilizers. The use of low cost by-product pet coke from the adjacent oil refinery as feedstock (rather than natural gas) to produce hydrogen provides the facility with a significant competitive advantage given the currently high and volatile natural gas prices. The plant s competition utilizes natural gas to produce ammonia.

## 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 CVR s outstanding term loan debt and to repay in full our $25 million secured credit facility and $25.0 million unsecured credit facility. We also repaid $50.0 million of indebtedness under our revolving credit facility.

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

## CVR Partners Proposed Initial Public Offering

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

## Major Influences on Results of Operations

*Petroleum Business.* Our earnings and cash flows from our petroleum operations are primarily affected by the relationship between refined product prices and the prices for crude oil and other feedstocks. Feedstocks are petroleum products, such as crude oil and natural gas liquids, that are processed and blended into refined products. The cost to acquire feedstocks and the price for which refined products are ultimately sold depend on factors beyond our control, including the supply of, and demand for, crude oil, as well as gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. Because we apply first-in, first-out, or FIFO, accounting to value our inventory, crude oil price movements may impact net income in the short term because of instantaneous changes in the value of the minimally required, unhedged on hand inventory. The effect of changes in crude oil prices on our results of operations is influenced by the rate at which the prices of refined products adjust to reflect these changes.

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

Crude oil costs are at historic highs. West Texas Intermediate crude oil, or WTI crude oil, which is used as a benchmark for other crude oils, averaged $97.82 per barrel for the three months ended March 31, 2008, as compared to $58.27 per barrel during the comparable period in 2007. WTI crude oil prices averaged over $105 per barrel in March 2008 and had spiked to over $126 per barrel as of May 13, 2008.

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

Although the 2-1-1 crack spread is a benchmark for our refinery margin, because our refinery has certain feedstock costs and/or logistical advantages as compared to a benchmark refinery and our product yield is less than total refinery throughput, the crack spread does not account for all the factors that affect refinery margin. Our refinery is able to process a blend of crude oil that includes quantities of heavy and medium sour crude oil that has historically cost less than WTI crude oil. We measure the cost advantage of our crude oil slate by calculating the spread between the price of our delivered crude oil to the price of WTI crude oil, a light sweet crude oil. The spread is referred to as our consumed crude differential. Our refinery margin can be impacted significantly by the consumed crude differential. Our consumed crude differential will move directionally with changes in the West Texas Sour (WTS) differential to WTI and the West Canadian Select (WCS) differential to WTI as both these differentials indicate the relative price of heavier, more sour, slate to WTI. The WCS-WTI differential for the first quarter of 2008 was $19.84 a barrel as compared to $14.80 a barrel in the first quarter of 2007. The differential for the fourth quarter of 2007 was $32.60 a barrel. This differential is now widening, in a contra-seasonal manner, which we can benefit from in terms of our weighted crude oil costs. The correlation between our consumed crude differential and published differentials will vary depending on the volume of light medium sour crude and heavy sour crude we purchase as a percent of our total crude volume and will correlate more closely with such published differentials the heavier and more sour the crude oil slate.

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

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

Consistent, safe, and reliable operations at our refinery are key to our financial performance and results of operations. Unplanned downtime at our refinery may result in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position.

*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 the majority of the pet coke feedstock needed by the nitrogen fertilizer business. 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 the low, high natural gas prices do not force the nitrogen fertilizer business to shut down its operations because it employs pet coke as a feedstock to produce ammonia and UAN rather than natural gas.

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

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

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

Prices for both ammonia and UAN for the quarter ended March 31, 2008 reflect strong current demand for these products. Ammonia plant gate prices averaged $494 per ton for the quarter ended March 31, 2008, compared to $347 per ton during the comparable period in 2007. UAN prices averaged $262 per ton for the quarter ended March 31, 2008, compared to $169 per ton during the comparable 2007 period.

The direct operating expense structure of the nitrogen fertilizer business is also important to its profitability. Using a pet coke gasification process, the nitrogen fertilizer business has significantly higher fixed costs than natural gas-based fertilizer plants. Major direct operating expenses include electrical energy, employee labor, maintenance, including contract labor, and outside services. These costs comprise the fixed costs associated with the fertilizer plant.

## Factors Affecting Comparability of Our Financial Results

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

### 2007 Flood and Crude Oil Discharge

During the weekend of June 30, 2007, torrential rains in southeast Kansas caused the Verdigris River to overflow its banks and flood the town of Coffeyville. Our refinery and nitrogen fertilizer plant, which are located in close proximity to the Verdigris River, were severely flooded, sustained major damage and required repairs.

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. The nitrogen fertilizer facility initiated startup at its production facility on July 13, 2007.

Total gross costs incurred and recorded as of March 31, 2008 related to the third party costs to repair the refinery and fertilizer facilities were approximately $82.5 million and $4.0 million, respectively. In addition, we currently estimate that approximately $2.1 million in third party costs related to the repair of flood damaged property will be recorded in future periods.

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In addition, despite our efforts to secure the refinery prior to its evacuation as a result of the flood, we estimate that 1,919 barrels (80,600 gallons) of crude oil and 226 barrels of crude oil fractions were discharged from our refinery into the Verdigris River flood waters beginning on or about July 1, 2007. We are currently remediating the contamination caused by the crude oil discharge. Total net costs recorded as of March 31, 2008 associated with remediation efforts and third party property damage incurred by the crude oil discharge are approximately $27.3 million. This amount is net of anticipated insurance recoveries of $21.4 million. In 2007, the Company had received insurance proceeds of $10.0 million under its property insurance policy, and $10.0 million under its environmental policies related to recovery of certain costs associated with the crude oil discharge.

Our results for the three months ended March 31, 2008 include pretax costs of $5.8 million associated with the flood and related crude oil discharge. This amount is net of anticipated insurance recoveries for the three months ended March 31, 2008 of $1.8 million. In the first quarter of 2008, the Company received $1.5 million under the Builder s Risk Insurance Policy.

Below is a summary of the gross cost arising from the flood and crude oil discharge and a reconciliation of the related insurance receivable (in millions):

| | Total Costs | For the Three Months Ended March 31, 2008 |
|---|---|---|
| Total gross costs incurred | $ 154.5 | $ 7.6 |
| Total insurance receivable | (107.2) | (1.8) |
| Net costs associated with the flood | $ 47.3 | $ 5.8 |

| | Receivable Reconciliation |
|---|---|
| Total insurance receivable | $ 107.2 |
| Less insurance proceeds received | (21.5) |
| Insurance receivable | $ 85.7 |

**Refinancing and Prior Indebtedness**

At December 31, 2006, we had a balance of $775.0 million on our term loan facility. In October 2007, we paid down $280.0 million of outstanding long-term debt with initial public offering proceeds. In addition, proceeds of our initial public offering were used to repay in full our $25.0 million secured credit facility, our $25.0 million unsecured credit facility and $50.0 million of indebtedness under our revolving credit facility. Our Statements of Operations for the three months ended March 31, 2008 includes interest expense of $11.3 million on the term debt of $488.0 million. Interest expense associated with the term debt for the three months ended March 31, 2007 totaled $11.9 million. Term debt as of March 31, 2007 totaled $775.0 million.

**J. Aron Deferrals**

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

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

Prior to our initial public offering in October 2007, our operations were conducted by an operating partnership, Coffeyville Resources, LLC. The reporting entity of the organization was also a partnership. Immediately prior to the closing of our initial public offering, Coffeyville Resources, LLC became an indirect, wholly-owned subsidiary of CVR Energy, 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.

**2007 Turnaround**

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

**Consolidation of Nitrogen Fertilizer Limited Partnership**

Prior to the consummation of our initial public offering, we transferred our nitrogen fertilizer business to the Partnership and sold the managing general partner interest in the Partnership to a new entity owned by our controlling stockholders and senior management. As of March 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. 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 46R).

Using criteria in FIN 46R, management has determined that we are the primary beneficiary of the Partnership, although 100% of the managing general partner interest is owned by a new entity owned by our controlling stockholders and senior management outside our reporting structure. Since we are the primary beneficiary, the financial statements of the Partnership remain consolidated in our financial statements. The managing general partner s interest is reflected as a minority interest on our balance sheet.

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

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

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

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

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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.

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**Results of Operations**

The following tables summarize the financial data and key operating statistics for CVR and our two operating segments for the three months ended March 31, 2008 and 2007. The summary financial data for our two operating segments does not include certain SG&A expenses and depreciation and amortization related to our corporate offices. The following data should be read in conjunction with our condensed consolidated financial statements and the notes thereto included elsewhere in this Form 10-Q. All information in Management s Discussion and Analysis of Financial Condition and Results of Operations , except for the balance sheet data as of December 31, 2007, is unaudited.

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

| | As of March 31, 2008 | As of December 31, 2007 |
|---|---|---|
| | (in millions, except as otherwise indicated) | |
| **Balance Sheet Data:** | | |

| | | |
|---|---|---|
| Cash and cash equivalents | $ 25.2 | $ 30.5 |
| Working capital | 21.5 | 10.7 |
| Total assets | 1,923.6 | 1,868.4 |
| Total debt, including current portion | 499.2 | 500.8 |
| Minority interest in subsidiaries | 10.6 | 10.6 |
| Stockholders equity | 455.1 | 432.7 |

| | **Three Months Ended March 31,** | |
|---|---|---|
| | **2008** | **2007** |
| | **(in millions)** | |
| | (unaudited) | (unaudited) |
| **Other Financial Data:** | | |
| Depreciation and amortization | $ 19.6 | $ 14.2 |
| Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap (3) | 30.6 | (82.4) |
| Cash flows provided by operating activities | 24.2 | 44.1 |
| Cash flows (used in) investing activities | (26.2) | (107.4) |
| Cash flows (used in) provided by financing activities | (3.4) | 29.0 |
| Capital expenditures for property, plant and equipment | 26.2 | 107.4 |

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| | Three Months Ended March 31, 2008 | 2007 |
|---|---|---|
| **Key Operating Statistics:** | | |
| **Petroleum Business** | | |
| Production (barrels per day) (4) | 125,614 | 53,689 |
| Crude oil throughput (barrels per day) (4) | 106,530 | 47,267 |
| **Nitrogen Fertilizer Business** | | |
| Production Volume: | | |
| Ammonia (tons in thousands) | 83.7 | 86.2 |
| UAN (tons in thousands) | 150.1 | 165.7 |

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

| | Three Months Ended March 31, 2008 (unaudited) (in millions) | 2007 |
|---|---|---|
| Depreciation and amortization included in cost of product sold | $ 0.6 | $ 0.6 |
| Depreciation and amortization included in direct operating expenses | 18.7 | 13.5 |
| Depreciation and amortization included in selling, general and administrative expenses | 0.3 | 0.1 |
| Total depreciation and amortization | $ 19.6 | $ 14.2 |

(2) The following are certain charges and costs incurred in each of the relevant periods that are

meaningful to understanding our net income (loss) and in evaluating our performance due to their unusual or infrequent nature:

| | Three Months Ended March 31, 2008 | 2007 |
|---|---|---|
| | (unaudited) (in millions) | |
| Funded letter of credit expense and interest rate swap not included in interest expense (a) | $ 0.9 | $ |
| Major scheduled turnaround expense (b) | | 66.0 |
| Unrealized loss from Cash Flow Swap | 13.9 | 119.7 |

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

(b) Represents expenses associated with

a major scheduled turnaround at the refinery.

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

derivative took the form of three NYMEX swap agreements whereby if 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. Based upon expected crude oil capacity of 115,000 bpd, the Cash Flow Swap represents approximately 58% and 14% of crude oil capacity for the periods January 1, 2008 through June 30, 2009 and July 1, 2009 through June 30, 2010, respectively. Under the terms of our Credit Facility and upon meeting specific requirements related to our leverage ratio and our credit ratings, we may reduce the Cash Flow Swap to 35,000 bpd, or approximately 30% of executed crude oil capacity, for the period from April 1, 2008 through December 31, 2008 and terminate the Cash Flow Swap in 2009 and 2010.

We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under current GAAP. As a result, our periodic statements of operations reflect 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 a liability on

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our balance sheet. As the crack spreads increase we are required to record an increase in this liability account with a corresponding expense entry to be made to our Statements of Operations. Conversely, as crack spreads decline we are required to record a decrease in the swap related liability and post a corresponding income entry to our statement of operations. Because of this inverse relationship between the economic outlook for our underlying business (as represented by crack spread levels) and the income impact of the unrecognized gains and losses, and given the significant periodic fluctuations in the amounts of unrealized gains and losses, management utilizes Net income (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 U.S. GAAP net income results as well as Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap. We believe that Net income (loss) adjusted for unrealized gain or loss from Cash Flow Swap enhances the understanding of our results of operations by highlighting income attributable to our ongoing operating performance exclusive of charges and income resulting from mark to market adjustments that are not necessarily indicative of the performance of our underlying business and our industry. The adjustment has been made for the unrealized loss from Cash Flow Swap net of its related tax benefit.

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

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

| | Three Months Ended March 31, 2008 | Three Months Ended March 31, 2007 |
|---|---|---|
| Net income (loss) adjusted for unrealized loss from Cash Flow Swap | $ 30.6 | $ (82.4) |
| Plus: | | |
| Unrealized (loss) from Cash Flow Swap, net of taxes | (8.4) | (72.0) |
| Net income (loss) | $ 22.2 | $ (154.4) |

(4) Barrels per day are calculated by dividing the volume in the

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

The following table shows selected information from our petroleum business including refining margin:

| | Three Months Ended March 31, 2008 | 2007 |
|---|---|---|
| | (unaudited) (in millions, except as otherwise indicated) | |
| **Petroleum Business:** | | |
| Net sales | $ 1,168.5 | $ 352.5 |
| Cost of product sold (exclusive of depreciation and amortization) | 1,035.1 | 298.5 |
| Direct operating expenses (exclusive of depreciation and amortization) | 40.3 | 96.7 |
| Net costs associated with flood | 5.5 | |
| Depreciation and amortization | 14.9 | 9.8 |
| Gross profit (loss) | $ 72.7 | $ (52.5) |
| Plus direct operating expenses (exclusive of depreciation and amortization) | 40.3 | 96.7 |
| Plus net costs associated with flood | 5.5 | |
| Plus depreciation and amortization | 14.9 | 9.8 |
| Refining margin (1) | $ 133.4 | $ 54.0 |
| Refining margin per crude oil throughput barrel | $ 13.76 | $ 12.69 |
| Gross profit (loss) per crude oil throughput barrel | $ 7.50 | $ (12.34) |
| Direct operating expenses (exclusive of depreciation and amortization) per crude oil throughput barrel | $ 4.16 | $ 22.73 |
| Operating income (loss) | 63.6 | (63.5) |

(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.

| | Three Months Ended March 31, 2008 | Three Months Ended March 31, 2007 |
|---|---|---|
| | (dollars per barrel) | |
| **Market Indicators** | | |
| West Texas Intermediate (WTI) crude oil | $97.82 | $ 58.27 |
| NYMEX 2-1-1 Crack Spread | 11.81 | 12.17 |
| Crude Oil Differentials: | | |
| WTI less WTS (sour) | 4.63 | 4.26 |
| WTI less WCS (heavy sour) | 19.84 | 14.80 |
| WTI less Dated Brent (foreign) | 1.10 | 0.51 |
| PADD II Group 3 versus NYMEX Basis: | | |
| Gasoline | (1.46) | (0.54) |
| Heating Oil | 3.65 | 8.77 |
| PADD II Group 3 versus NYMEX Crack: | | |
| Gasoline | 4.95 | 12.43 |
| Heating Oil | 20.77 | 20.57 |
| | | |
| **Company Operating Statistics** | | |
| Per barrel profit, margin and expense of crude oil throughput: | | |
| Refining margin | $13.76 | $ 12.69 |
| Gross profit (loss) | 7.50 | (12.34) |
| Direct operating expenses (exclusive of depreciation and amortization) | 4.16 | 22.73 |
| Per gallon sales price: | | |
| Gasoline | 2.45 | 1.59 |
| Distillate | 2.85 | 1.78 |

| | Three Months Ended March 31, 2008 | | 2007 | |
|---|---|---|---|---|
| | Barrels Per Day | % | Barrels Per Day | % |
| **Selected Company Volumetric Data** | | | | |
| Production: | | | | |
| Total gasoline | 59,662 | 47.5 | 23,499 | 43.8 |
| Total distillate | 48,591 | 38.7 | 21,976 | 40.9 |
| Total other | 17,361 | 13.8 | 8,214 | 15.3 |
| | | | | |
| Total all production | 125,614 | 100.0 | 53,689 | 100.0 |
| Crude oil throughput | 106,530 | 89.0 | 47,267 | 92.7 |
| All other inputs | 13,197 | 11.0 | 3,716 | 7.3 |
| | | | | |
| Total feedstocks | 119,727 | 100.0 | 50,983 | 100.0 |

**Three Months Ended**
**March 31,**

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | **Total Barrels** | **%** | **Total Barrels** | **%** |
| Crude oil throughput by crude type: | | | | |
| Sweet | 6,573,627 | 67.8 | 2,782,136 | 65.4 |
| Light/medium sour | 1,785,669 | 18.4 | 1,454,878 | 34.2 |
| Heavy sour | 1,334,889 | 13.8 | 17,016 | 0.4 |
| Total crude oil throughput | 9,694,185 | 100.0 | 4,254,030 | 100.0 |

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

| | Three Months Ended March 31, 2008 | Three Months Ended March 31, 2007 |
|---|---|---|
| | (unaudited) (in millions, except as otherwise indicated) | |
| **Nitrogen Fertilizer Business:** | | |
| Net sales | $ 62.6 | $ 38.6 |
| Cost of product sold (exclusive of depreciation and amortization) | 8.9 | 6.1 |
| Direct operating expenses (exclusive of depreciation and amortization) | 20.3 | 16.7 |
| Depreciation and amortization | 4.5 | 4.4 |
| Operating income | 26.0 | 9.3 |

| | Three Months Ended March 31, 2008 | Three Months Ended March 31, 2007 |
|---|---|---|
| **Market Indicators** | | |
| Natural gas (dollars per MMBtu) | $8.74 | $7.17 |
| Ammonia Southern Plains (dollars per ton) | 590 | 389 |
| UAN Corn Belt (dollars per ton) | 371 | 239 |

| | Three Months Ended March 31, 2008 | Three Months Ended March 31, 2007 |
|---|---|---|
| **Company Operating Statistics** | | |
| Production (thousand tons): | | |
| Ammonia | 83.7 | 86.2 |
| UAN | 150.1 | 165.7 |
| Total | 233.8 | 251.9 |
| Sales (thousand tons) (1): | | |
| Ammonia | 24.1 | 20.7 |
| UAN | 158.0 | 166.8 |
| Total | 182.1 | 187.5 |
| Product pricing (plant gate) (dollars per ton) (1): | | |
| Ammonia | $ 494 | $ 347 |
| UAN | 262 | 169 |
| On-stream factor (2): | | |
| Gasification | 91.8% | 91.8% |
| Ammonia | 90.7% | 86.3% |
| UAN | 85.9% | 89.4% |

| | | |
|---|---|---|
| Reconciliation to net sales (dollars in thousands): | | |
| Freight in revenue | $ 4,022 | $ 3,139 |
| Hydrogen revenue | 5,291 | |
| Sales net plant gate | 53,287 | 35,436 |
| Total net sales | 62,600 | 38,575 |

(1) Plant gate sales per ton represents 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.

(2) On-stream factor is the total number of hours operated divided by the total number of hours in the reporting period.

**Three Months Ended March 31, 2008 Compared to the Three Months Ended March 31, 2007**

**Consolidated Results of Operations**

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

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

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

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

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

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

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

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

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

***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 three months ended March 31, 2008, we incurred $47.9 million in losses on derivatives. This compares to a $137.0 million loss on derivatives for the three months ended March 31, 2007. This significant decrease in loss on derivatives, net for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily attributable to the realized and unrealized losses on our Cash Flow Swap. Realized losses on the Cash Flow Swap for the three months ended March 31, 2008 and the three months ended March 31, 2007 were $21.5 million and $8.5 million, respectively. The increase in realized losses over the comparable periods was primarily the result of higher average crack spreads for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007. Unrealized losses represent the change in the mark-to-market value on the unrealized portion of the Cash Flow Swap based on changes in the NYMEX crack spread that is the basis for the Cash Flow Swap. Unrealized losses on our Cash Flow Swap for the three months ended March 31, 2008 and the three months ended March 31, 2007 were $13.9 million and $119.7 million, respectively. This change in the unrealized loss of the Cash Flow Swap over the comparable periods reflect decreases in the crack spread values on the unrealized positions comprising the Cash Flow Swap. In addition to the change in the NYMEX crack spread, the outstanding term of the Cash Flow Swap at the end of each period also affects the impact that the changes of the underlying crack spread may have on the unrealized gain or loss. As of March 31, 2008, the Cash Flow Swap had a remaining term of approximately two years and three months whereas as of March 31, 2007 the remaining term on the Cash Flow Swap was approximately three years and three months. As a result of the shorter remaining term as of March 31, 2008, a similar change in crack spread will have a smaller impact on the unrealized gains or losses.

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

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

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

**Petroleum Results of Operations**

***Net Sales.*** Petroleum net sales were $1,168.5 million for the three months ended March 31, 2008 compared to $352.5 million for the three months ended March 31, 2007. The increase of $816.0 million during the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of significantly higher sales volumes ($592.1 million) and higher product prices ($223.9 million). Overall sales volumes of refined fuels for the three months ended March 31, 2008 increased 110% as compared to the three months ended March 31,

2007. The increased sales volume primarily resulted from a significant increase in refined fuel

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production volumes over the comparable periods due to the refinery turnaround which began in February 2007 and was completed in April 2007. Our average sales price per gallon for the three months ended March 31, 2008 for gasoline of $2.45 and distillate of $2.85 increased by 54% and 60%, respectively, as compared to the three months ended March 31, 2007.

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

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

***Direct Operating Expenses Exclusive of Depreciation and Amortization.*** Direct operating expenses for our petroleum operations include costs associated with the actual operations of our refinery, such as energy and utility costs, catalyst and chemical costs, repairs and maintenance (turnaround), labor and environmental compliance costs. Petroleum direct operating expenses exclusive of depreciation and amortization were $40.3 million for the three months ended March 31, 2008 compared to direct operating expenses of $96.7 million for the three months ended March 31, 2007. The decrease of $56.4 million for the three months ended March 31, 2008 compared to the three months ended March 31, 2007 was the result of decreases in expenses associated with refinery turnaround ($66.0 million) and direct labor ($1.7 million). These decreases in direct operating expenses were partially offset by increases in expenses associated with utilities and energy ($4.3 million), repairs and maintenance ($3.0 million), production chemicals ($2.1 million), property taxes ($0.8 million) and environmental ($0.5 million). On a per barrel of crude throughput basis, direct operating expenses per barrel of crude oil throughput for the three months ended March 31, 2008 decreased to $4.16 per barrel as compared to $22.73 per barrel for the three months ended March 31, 2007 principally due to the 2007 downtime at the refinery for planned major maintenance and the corresponding impact on overall crude oil throughput and production volume.

***Net Costs Associated with Flood.*** Petroleum net costs associated with flood for the three months ended March 31, 2008 approximated $5.5 million. As the flood occurred in the second and third quarter of 2007, there were no flood related costs incurred in the first quarter of 2007. Total gross costs recorded for the three months ended March 31, 2008 were approximately $6.8 million. Of these gross costs approximately $3.0 million were associated with repair and other matters as a result of the physical damage to the refinery and approximately $3.8

million were associated with the environmental remediation and property damage. Total accounts receivable from insurers approximated $81.2 million at March 31, 2008, for which we believe collection is probable.

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

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

**Fertilizer Results of Operations**

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

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

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

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

***Cost of Product Sold Exclusive of Depreciation and Amortization.*** Cost of product sold exclusive of depreciation and amortization is primarily comprised of pet coke expense and freight and distribution expenses. Cost of product sold (excluding depreciation and amortization) for the three months ended March 31, 2008 was $8.9 million compared to $6.1 million for the three months ended March 31, 2007. The increase of $2.8 million for the three months ended

March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of a change in accounting for hydrogen reimbursement. For the three months ended March 31, 2007, hydrogen reimbursement was included in cost of product sold (exclusive of depreciation and amortization). For the three months ended March 31, 2008, hydrogen has been included in net sales. These amounts eliminate in consolidation. Hydrogen is transferred from our nitrogen fertilizer operations to our petroleum operations to facilitate sulfur recovery in the ultra low sulfur diesel production unit.

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

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

***Operating Income.*** Nitrogen fertilizer operating income was $26.0 million for the three months ended March 31, 2008 as compared to operating income of $9.3 million for the three months ended March 31, 2007. This increase of $16.7 million for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was primarily the result of increased fertilizer prices over the comparable periods. Additionally, decreased direct operating expenses associated with utilities ($0.6 million), royalties and other ($0.4 million) and equipment rental ($0.3 million) also contributed to the positive operating income comparison over the comparable periods. These decreases in expenses were partially offset by reduced sales volumes and increased direct operating expenses primarily the result of increases in taxes ($2.5 million), repairs and maintenance ($1.7 million), labor ($0.3 million), catalysts ($0.3 million) and outside services ($0.2 million).

## Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operating activities, existing cash balances and our existing revolving credit facility. Additionally, we have borrowings from related parties. Our ability to generate sufficient cash flows from our operating activities will continue to be primarily dependent on producing or purchasing, and selling, sufficient quantities of refined products at margins sufficient to cover fixed and variable expenses.

Our liquidity was enhanced during the fourth quarter of 2007 by the receipt of $408.5 million of net proceeds from our initial public offering after the payment of underwriting discounts and commissions, but before the deduction of offering expenses. We believe that our cash flows from operations, borrowings under our revolving credit facility, third party guarantees and other capital resources will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next 12 months. However, our future capital expenditures and other cash requirements could be higher than we currently expect as a result of various factors. Additionally, our ability to generate sufficient cash from our operating activities depends on our future performance, which is subject to general economic, political, financial, competitive, and other factors beyond our control.

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## Debt

### *Credit Facility*

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

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

The revolving 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 March 31, 2008, we had available $112.6 million under the revolving credit facility.

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

The Credit Facility incorporates the following pricing by facility type:

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

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

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

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

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

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

100% of the net asset sale proceeds received from specified asset sales and net insurance/ condemnation proceeds, if the borrower does not reinvest those proceeds in assets to be used in its

business or make other permitted investments within 12 months or if, within 12 months of receipt, the borrower does not contract to reinvest those proceeds in assets to be used in its business or make other permitted investments within 18 months of receipt, each subject to certain limitations;

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

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

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

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

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

| **Fiscal quarter ending** | **Minimum interest coverage ratio** | **Maximum leverage ratio** |
|---|---|---|
| March 31, 2008 | 3.25:1.00 | 3.25:1.00 |
| June 30, 2008 | 3.25:1.00 | 3.00:1.00 |
| September 30, 2008 | 3.25:1.00 | 2.75:1.00 |
| December 31, 2008 | 3.25:1.00 | 2.50:1.00 |
| March 31, 2009 and thereafter | 3.75:1.00 | 2.25:1.00 to December 31, 2009, 2.00:1.00 thereafter |

The computation of these ratios is governed by the specific terms of the Credit Facility and may not be comparable to other similarly titled measures computed for other purposes or by other companies. The minimum interest coverage ratio is the ratio of consolidated adjusted EBITDA to consolidated cash interest expense over a four quarter period. The maximum leverage ratio is the ratio of consolidated total debt to consolidated adjusted EBITDA over a four quarter period. The computation of these ratios requires a calculation of consolidated adjusted EBITDA. In general, under the terms of our Credit Facility, consolidated adjusted EBITDA is calculated by adding consolidated net income, consolidated interest expense, income taxes, depreciation and amortization, other non- cash expenses, any fees and expenses related to permitted acquisitions, any non-recurring expenses incurred in connection with the issuance of debt or equity, management fees, any unusual or non-recurring charges up to 7.5% of consolidated adjusted EBITDA, any net after-tax loss from disposed or discontinued operations, any incremental property taxes related to abatement non-renewal, any losses attributable to minority equity interests and major scheduled turnaround expenses. As of March 31, 2008, we were in compliance with our covenants under the Credit Facility.

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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:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2008 | 2007 |
| | (unaudited in millions) | |
| **Consolidated Financial Results** | | |
| Net income (loss) | $ 22.2 | $ (154.4) |
| Plus: | | |
| Depreciation and amortization | 19.6 | 14.2 |
| Interest expense and other financing costs | 11.3 | 11.9 |
| Income tax expense (benefit) | 6.9 | (47.3) |
| Funded letters of credit expense and interest rate swap not included in interest expense | 0.9 | |
| Major scheduled turnaround expense | | 66.0 |
| Unrealized (gain) or loss on derivatives | 18.9 | 126.9 |
| Non-cash compensation expense for equity awards | (0.4) | 3.7 |
| Minority interest | | (0.7) |
| Management fees | | 0.5 |
| Adjusted EBITDA | $ 79.4 | $ 20.8 |

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

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

Under the terms of our Credit Facility, our initial public offering was deemed a Qualified IPO because the offering generated at least $250 million of gross proceeds and we used the proceeds of the offering to repay at least $275 million of term loans under the Credit Facility. As a result of our Qualified IPO, the interest margin on LIBOR loans may in the future decrease from 3.25% to 2.75% (if we have credit ratings of B2/B) or 2.50% (if we have credit ratings of B1/B+). Interest on base rate loans will similarly be adjusted. In addition, as a result of our Qualified IPO, (1) we will be allowed to borrow an additional $225 million under the Credit Facility after June 30, 2008 to finance capital enhancement projects if we are in pro forma compliance with the financial covenants in the Credit Facility and the rating agencies confirm our ratings, (2) we will be allowed to pay an additional $35 million of dividends each year, if our corporate family ratings are at least B2 from Moody s and B from S&P, (3) we will not be subject to any capital expenditures limitations commencing with fiscal 2009 if our total leverage ratio is less than or equal to 1.25:1 for any quarter commencing with the quarter ended December 31, 2008, and (4) at any time after March 31, 2008 we will be allowed to reduce the Cash Flow Swap to not less than 35,000 barrels a day for fiscal 2008 and terminate the Cash Flow Swap for any year commencing with fiscal 2009, so long as our total leverage ratio is less than or equal to 1.25:1 and we have a corporate family rating of at least B2 from Moody s and B from S&P.

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

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

***Payment Deferrals Related to Cash Flow Swap***

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

On June 26, 2007, Coffeyville Resources, LLC and J. Aron & Company entered into a letter agreement in which J. Aron deferred to August 7, 2007 a $45 million payment which we owed to J. Aron under the Cash Flow Swap for the period ending June 30, 2007. We agreed to pay interest on the deferred amount at the rate of LIBOR plus 3.25%.

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

On July 26, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to September 7, 2007 both the $45 million payment due August 7, 2007 (and accrued interest) and the $43.7 million payment due July 25, 2007 (and accrued interest). J. Aron deferred these payments on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts from July 26, 2007 to the date of payment at the rate of LIBOR plus 1.50%.

On August 23, 2007, Coffeyville Resources, LLC and J. Aron entered into a letter agreement in which J. Aron deferred to January 31, 2008 the $45 million payment due September 7, 2007 (and accrued interest), the $43.7 million payment due September 7, 2007 (and accrued interest) and the $35 million payment which we owed to J. Aron under the Cash Flow Swap to settle hedged volume through August 15, 2007. J. Aron deferred these payments (totaling $123.7 million plus accrued interest) on the conditions that (a) each of GS Capital Partners V Fund, L.P. and Kelso Investment Associates VII, L.P. agreed to guarantee one half of the payments and (b) interest accrued on the amounts to the date of payment at the rate of LIBOR plus 1.50%.

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***Nitrogen Fertilizer Limited Partnership***

The managing general partner of the Partnership may, from time to time, seek to raise capital through a public or private offering of limited partner interests in the Partnership. Any decision to pursue such a transaction would be made in the discretion of the managing general partner, not us, and any proceeds raised in a primary offering would be for the benefit of the Partnership, not us (although in some cases, depending on the structure of the transaction, the Partnership might remit proceeds to us). As discussed elsewhere, the Partnership has filed a registration statement with the SEC regarding a potential initial public offering of limited partner interests, although there is no assurance that the Partnership will consummate any such offering on the terms described in the registration statement, or at all. If the managing general partner elects to pursue a public or private offering of limited partner interests in the Partnership, we expect that any such transaction would require amendments to our Credit Facility, as well as the Cash Flow Swap, in order to remove the Partnership and its subsidiaries as obligors under such instruments. Any such amendments could result in significant changes to our Credit Facility s pricing, mandatory repayment provisions, covenants and other terms and could result in increased interest costs and require payment by us of additional fees. We have agreed to use our commercially reasonable efforts to obtain such amendments if the managing general partner elects to cause the Partnership to pursue a public or private offering and gives us at least 90 days written notice.

However, we cannot assure you that we will be able to obtain any such amendment on terms acceptable to us or at all. If we are not able to amend our Credit Facility on terms satisfactory to us, we may need to refinance them with other facilities. We will not be considered to have used our commercially reasonable efforts to obtain such amendments if we do not effect the requested modifications due to (i) payment of fees to the lenders or the swap counterparty, (ii) the costs of this type of amendment, (iii) an increase in applicable margins or spreads or (iv) changes to the terms required by the lenders including covenants, events of default and repayment and prepayment provisions; provided that (i), (ii), (iii) and (iv) in the aggregate are not likely to have a material adverse effect on us. In order to effect the requested amendments, we may require that (1) the Partnership s initial public or private offering generate at least $140 million in net proceeds to us and (2) the Partnership raise an amount of cash (from the issuance of equity or incurrence of indebtedness) equal to $75 million minus the amount of capital expenditures it will reimburse us for from the proceeds of its initial public or private offering and to distribute that cash to us prior to, or concurrently with, the closing of its initial public or private offering. If the managing general partner sells interests to third party investors, we expect that the Partnership may at such time seek to enter into its own credit facility.

In addition, we may elect to sell our interests in the Partnership in a secondary public offering (either in connection with a public offering by the Partnership, but subject to priority rights in favor of the Partnership, or following completion of the Partnership s initial public offering, if any) or in a private placement. Neither the consent of the managing general partner nor the consent of the Partnership is required for any sale of our interests in the Partnership, other than customary blackout periods relating to offerings by the Partnership. Any proceeds raised would be for our benefit. The Partnership has granted us registration rights which will require the Partnership to register our interests with the SEC at our request from time to time (following any public offering by the Partnership), subject to various limitations and requirements.

**Capital Spending**

In 2007, as a result of the flood, our refinery exceeded the required average annual gasoline sulfur standard as mandated by our approved hardship waiver with the EPA. In anticipation of a settlement with the EPA to resolve the non-compliance, the Company planned to spend $28.0 million in capital required for interim compliance with the ultra low sulfur gasoline standards in 2008, ahead of the required full compliance date of January 1, 2011. During 2008, the matter was resolved with the EPA and accordingly, $9.7 million of planned capital spending was deferred to 2009.

**Cash Flows**

The following table sets forth our cash flows for the periods indicated below (in thousands):

| | **Three Months Ended March 31,** | |
|---|---|---|
| | **2008** | **2007** |
| Net cash provided by (used in): | | |

| | | |
|---|---|---|
| Operating activities | $ 24,194 | $ 44,105 |
| Investing activities | (26,156) | (107,363) |
| Financing activities | (3,368) | 28,947 |
| Net increase (decrease) in cash and cash equivalents | $ (5,330) | $ (34,311) |

***Cash Flows Provided by Operating Activities***

Net cash flows from operating activities for the three months ended March 31, 2008 was $24.2 million. The positive cash flow from operating activities generated over this period was primarily driven by favorable changes in other working capital and other assets and liabilities, partially offset by unfavorable changes in trading working capital over the period. For purposes of this cash flow discussion, we define trade working capital as accounts receivable, inventory and accounts payable. Other working capital is defined as all other current assets and liabilities except trade working capital. Net income for the period was not indicative of the operating margins for the period. This is the result of the accounting treatment of our derivatives in general and, more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the three months ended March 31, 2008 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of March 31, 2008 (approximately two years and three months) and the NYMEX crack spread that is the basis for the underlying swaps had increased, the unrealized losses on the Cash Flow Swap significantly decreased our net income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $20.8 million increase in the payable to swap counterparty. Other sources of cash in other working capital included $16.6 million of deferred revenue related to prepaid fertilizer shipments and a $5.2 increase in accrued income taxes. Trade working capital for the three months ended March 31, 2008 resulted in a use of cash of $67.5 million. For the three months ended March 31, 2008, accounts receivable increased $30.7 million, inventory increased by $31.6 and accounts payable decreased by $5.2 million.

Net cash flows provided by operating activities for the three months ended March 31, 2007 was $44.1 million. The positive cash flow from operating activities during this period was primarily the result of changes in other assets and liabilities offset by unfavorable changes in trade working capital and other working capital. Net income for the period was not indicative of the operating margins for the period. This was the result of the accounting treatment of our derivatives in general and, more specifically, the Cash Flow Swap. We have determined that the Cash Flow Swap does not qualify as a hedge for hedge accounting purposes under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Therefore, the net loss for the three months ended March 31, 2007 included both the realized losses and the unrealized losses on the Cash Flow Swap. Since the Cash Flow Swap had a significant term remaining as of March 31, 2007 (approximately three years and three months years) and the NYMEX crack spread that is the basis for the underlying swaps had increased during the period, the unrealized losses on the Cash Flow Swap significantly decreased our net income over this period. The impact of these unrealized losses on the Cash Flow Swap is apparent in the $129.3 million increase in the payable to swap counterparty. Adding to our operating cash flow for the three months ended March 31, 2007 was a $68.0 million source of cash related to a decrease in trade working capital. For the three months ended March 31, 2007, accounts receivable decreased $44.6 million while inventory increased $23.0 million and accounts payable increased $46.4 million. The change in trade working capital was primarily driven by the impact of the refinery turnaround that began in February 2007. The primary use of cash during the period was $41.3 million for deferred income taxes primarily the result of the unrealized loss on the Cash Flow Swap.

***Cash Flows Used in Investing Activities***

Net cash used in investing activities for the three months ended March 31, 2008 was $26.2 million compared to $107.4 million for the three months ended March 31, 2007. The decrease in investing activities for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007 was the result of decreased capital expenditures associated with various capital projects that commenced in the first quarter of 2007 in conjunction with the refinery turnaround.

***Cash Flows (Used in) Provided by Financing Activities***

Net cash used for financing activities for the three months ended March 31, 2008 was $3.4 million as compared to net cash provided by financing activities of $29.0 million for the three months ended March 31, 2007. During the three months ended March 31, 2008, we paid $1.2 million of scheduled principal payments and deferred $2.1 million of initial public offering costs related to CVR Partners, LP. For the three months ended March 31, 2007, the primary source of cash was the result of borrowings drawn on our revolving credit facility.

**Working Capital**

Working capital at March 31, 2008, was $21.5 million, consisting of $622.5 million in current assets and $601.0 million in current liabilities. Working capital at December 31, 2007 was $10.7 million, consisting of $570.2 million in current assets and $559.5 million in current liabilities. In addition, we had available borrowing capacity under our revolving credit facility of $112.6 million at March 31, 2008.

**Letters of Credit**

Our revolving credit facility provides for the issuance of letters of credit. At March 31, 2008, there were $37.4 million of irrevocable letters of credit outstanding, including $5.8 million in support of certain environmental obligators and $31.6 million to secure transportation services for crude oil.

**Off-Balance Sheet Arrangements**

We had no off-balance sheet arrangements as of March 31, 2008.

**Recent Accounting Pronouncements**

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement on Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, which establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 states that fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price), not the price that would be paid to acquire the asset or received to assume the liability (an entry price). The standard s provisions for financial assets and financial liabilities, which became effective January 1, 2008, had no material impact on the Company s financial position or results of operations. At March 31, 2008, the only financial assets and financial liabilities that are measured at fair value on a recurring basis are the Company s derivative instruments. See Note 14, Fair Value Measurements.

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. Under this standard, an entity is required to provide additional information that will assist investors and other users of financial information to more easily understand the effect of the Company s choice to use fair value on its earnings. Further, the entity is required to display the fair value of those assets and liabilities for which the Company has chosen to use fair value on the face of the balance sheet. This standard does not eliminate the disclosure requirements about fair value measurements included in SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*. The provisions of SFAS 159 were effective for CVR as of January 1, 2008. The Company did not elect the fair value option under this standard upon adoption. Therefore, the adoption of SFAS 159 did not impact the Company s consolidated financial statements as of the quarter ended March 31, 2008.

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

In December 2007, the FASB issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements an amendment of ARB No. 51*. SFAS 160 establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 must be applied prospectively.

SFAS 160 is effective for CVR beginning January 1, 2009. The Company is currently evaluating the potential impact of the adoption of SFAS 160 on its consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement will change the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, net earnings, and cash flows. The Company will be required to adopt this statement as of January 1, 2009. The adoption of SFAS 161 is not expected to have a material impact on the Company s consolidated financial statements.

**Critical Accounting Policies**

The Company s critical accounting policies are disclosed in the Critical Accounting Policies section of our Annual Report on Form 10-K/A for the year ended December 31, 2007. No modifications have been made to the Company s critical accounting policies.

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

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

**Commodity Price Risk**

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

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

- lock in or fix a percentage of the anticipated or planned gross margin in future periods when the derivative market offers commodity spreads that generate positive cash flows

- hedge the value of inventories in excess of minimum required inventories; and

- hedge the value of inventories held with respect to our rack marketing business.

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

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

Our selection of the appropriate index to utilize in a hedging strategy is a prime consideration in our basis risk exposure.

Examples of our basis risk exposure are as follows:

Time Basis In entering over-the counter swap agreements, the settlement price of the swap is typically the average price of the underlying commodity for a designated calendar period. This settlement price is based on the assumption that the underlying physical commodity will price ratably over the swap period. If the commodity does not move ratably over the periods then weighted average physical prices will be weighted differently than the swap price as the result of timing.

Location Basis In hedging NYMEX crack spreads, we experience location basis as the settlement of NYMEX refined products (related more to New York Harbor cash markets) which may be different than the prices of refined products in our Group 3 pricing area.

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

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

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

As of March 31, 2008, a $1.00 change in quoted futures price for the crack spreads described in the first bullet point would result in a $36.2 million change to the fair value of the derivative commodity position and the same change in net income.

**Interest Rate Risk**

As of March 31, 2008, all of our $488.0 million of outstanding term debt was at floating rates. An increase of 1.0% in the LIBOR rate would result in an increase in our interest expense of approximately $4.9 million per year.

In an effort to mitigate the interest rate risk highlighted above and as required under our then-existing first and second lien credit agreements, we entered into several interest rate swap agreements in 2005. These swap agreements were entered into with counterparties that we believe to be creditworthy. Under the swap agreements, we pay fixed rates and receive floating rates based on the three-month LIBOR rates, with payments calculated on the notional amounts set for 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 three months ended March 31, 2008, we had $5.6 million of realized and unrealized losses on these interest rate swaps and for the three months ended March 31, 2007, we had $0.6 million of realized and unrealized losses.

**Item 4. Controls and Procedures**

***Evaluation of Disclosure Controls and Procedures***

We have established disclosure controls and procedures (Disclosure Controls) to ensure that information required to be disclosed in the Company s reports filed 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. Disclosure Controls are also designed to ensure that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Our Disclosure Controls were designed to provide reasonable assurance that the controls and procedures would meet their objectives. Our management, including the Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls will prevent all error and fraud. A control system, no matter how well designed and operated, can provide only reasonable assurance of achieving the designed control objectives and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusions of two or more people, or by management override of the control. Because of the inherent limitations in a cost-effective, maturing control system, misstatements due to error or fraud may occur and not be detected.

At March 31, 2008, we identified material weaknesses in our internal controls relating to the calculation of the cost of crude oil purchased by us and associated financial transactions. Specifically, our policies and procedures for estimating the cost of crude oil and reconciling these estimates to vendor invoices were not effective. Additionally, our supervision and review of this estimation and reconciliation process was not operating at a level of detail adequate to identify the deficiencies in the process. Management has concluded that these deficiencies are material weaknesses. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company s annual or interim financial statements will not be prevented or detected on a timely basis.

In order to remediate the material weaknesses described above, our management is in the process of designing, implementing and enhancing controls to ensure the proper accounting for the calculation of the cost of crude oil. These remedial actions include, among other things, (1) centralizing all crude oil cost accounting functions, (2) adding additional layers of accounting review with respect to our crude oil cost accounting and (3) adding additional layers of business review with respect to the computation of our crude oil costs. However, because of the timing of the filing of our Annual Report on Form 10-K/A for the year ended December 31, 2007, and the period covered by this Form 10-Q, we had not commenced our remediation of these material weaknesses at March 31, 2008.

As of the end of the period covered by this Form 10-Q, we evaluated the effectiveness of the design and operation of our Disclosure Controls. The evaluation of our Disclosure Controls was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, and included consideration of the material weaknesses described above. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our Disclosure Controls and procedures were not effective as of the end

of the period covered by this Quarterly Report on Form 10-Q because of the material weakness described above.
***Changes in Internal Control Over Financial Reporting***
No changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) occurred during the first quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. However, we are currently taking remedial actions to address the material weaknesses described above under Evaluation of Disclosure Controls and Procedures.

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**Part II. Other Information**

**Item 1A. Risk Factors**

There are no material changes to the risk factors previously disclosed in our 2007 Form 10-K/A for the year ended December 31, 2007 under Part I Item 1A. Risk Factors .

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## Item 6. Exhibits

| Number | Exhibit Title |
|---|---|
| 10.1 | Consulting Agreement, dated May 2, 2008, by and between General Wesley Clark and CVR Energy, Inc. |
| 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 |

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## SIGNATURES

Pursuant to the requirements 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, this fifteenth day of May 2008.

**CVR Energy, Inc.**

By: /s/ John J. Lipinski
Chief Executive Officer
(Principal Executive Officer)

By: /s/ James T. Rens
Chief Financial Officer
(Principal Financial Officer)