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

# FORM 10-Q

(Mark One)

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

**For the quarterly period ended March 31, 2012**

**or**

☐ **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: 001-32678**

# DCP MIDSTREAM PARTNERS, LP
**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware**<br>**(State or other jurisdiction of incorporation or organization)** | **03-0567133**<br>**(I.R.S. Employer Identification No.)** |
| **370 17th Street, Suite 2775**<br>**Denver, Colorado**<br>**(Address of principal executive offices)** | **80202**<br>**(Zip Code)** |

**Registrant's telephone number, including area code: (303) 633-2900**

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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.

| | | | |
|---|---|---|---|
| Large accelerated filer | ☒ | Accelerated filer | ☐ |
| Non-accelerated filer | ☐ | Smaller reporting company | ☐ |

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

As of May 4, 2012, there were outstanding 51,755,841 common units representing limited partner interests.

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**DCP MIDSTREAM PARTNERS, LP**
**FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2012**

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## GLOSSARY OF TERMS

The following is a list of certain industry terms used throughout this report:

| | |
|---|---|
| Bbl | barrel |
| Bbls/d | barrels per day |
| Bcf | one billion cubic feet |
| Bcf/d | one billion cubic feet per day |
| Btu | British thermal unit, a measurement of energy |
| Fractionation | the process by which natural gas liquids are separated into individual components |
| Frac spread | price differences, measured in energy units, between equivalent amounts of natural gas and NGLs |
| MBbls | one thousand barrels |
| MMBbls | one million barrels |
| MBbls/d | one thousand barrels per day |
| MMBtu | one million Btus |
| MMBtu/d | one million Btus per day |
| MMcf | one million cubic feet |
| MMcf/d | one million cubic feet per day |
| NGLs | natural gas liquids |
| Throughput | the volume of product transported or passing through a pipeline or other facility |

## CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2011, as well as the following risks and uncertainties:

- the extent of changes in commodity prices and the demand for our products and services, our ability to effectively limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price and producers' access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- general economic, market and business conditions;
- the level and success of natural gas drilling around our assets, the level and quality of gas production volumes around our assets and our ability to connect supplies to our gathering and processing systems in light of competition;
- our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates and our ability to effectively limit a portion of the adverse effects of potential changes in interest rates by entering into derivative financial instruments, our ability to comply with the covenants in our loan agreements and our debt securities, as well as our ability to maintain our credit ratings;
- the demand for NGL products by the petrochemical, refining or other industries or by the fuel markets;
- our ability to purchase propane from our suppliers and make associated profitable sales transactions for our wholesale propane logistics business;
- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for materials;
- the creditworthiness of counterparties to our transactions;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third-party-owned infrastructure;
- new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation and hydraulic fracturing regulations, or the increased regulation of our industry;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- industry changes, including the impact of consolidations, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition; and
- the amount of collateral we may be required to post from time to time in our transactions, including changes resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. The forward-looking statements in this report speak as of the filing date of this report. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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## PART I. FINANCIAL INFORMATION

**Item 1.** *Financial Statements*

### DCP MIDSTREAM PARTNERS, LP
### CONDENSED CONSOLIDATED BALANCE SHEETS
### (Unaudited)

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 6.1 | $ 7.6 |
| Accounts receivable: | | |
| Trade, net of allowance for doubtful accounts of $0.3 million and $0.3 million, respectively | 70.1 | 108.6 |
| Affiliates | 106.7 | 106.2 |
| Inventories | 69.0 | 87.9 |
| Unrealized gains on derivative instruments | 38.2 | 41.2 |
| Other | 1.3 | 2.2 |
| Total current assets | 291.4 | 353.7 |
| Property, plant and equipment, net | 1,546.1 | 1,499.4 |
| Goodwill | 153.8 | 153.8 |
| Intangible assets, net | 143.2 | 145.3 |
| Investments in unconsolidated affiliates | 108.5 | 107.1 |
| Unrealized gains on derivative instruments | 31.2 | 6.4 |
| Other long-term assets | 14.7 | 11.7 |
| Total assets | $2,288.9 | $ 2,277.4 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable: | | |
| Trade | $ 168.0 | $ 231.7 |
| Affiliates | 38.5 | 46.8 |
| Unrealized losses on derivative instruments | 52.6 | 59.9 |
| Other | 45.4 | 42.1 |
| Total current liabilities | 304.5 | 380.5 |
| Long-term debt | 865.2 | 746.8 |
| Unrealized losses on derivative instruments | 36.5 | 32.8 |
| Other long-term liabilities | 22.2 | 19.0 |
| Total liabilities | 1,228.4 | 1,179.1 |
| Commitments and contingent liabilities | | |
| Equity: | | |
| Predecessor equity | — | 257.4 |
| Common unitholders (51,755,841 and 44,848,703 units issued and outstanding, respectively) | 1,047.5 | 654.4 |
| General partner | (3.4) | (4.7) |
| Accumulated other comprehensive loss | (19.2) | (21.2) |
| Total partners' equity | 1,024.9 | 885.9 |
| Noncontrolling interests | 35.6 | 212.4 |
| Total equity | 1,060.5 | 1,098.3 |
| Total liabilities and equity | $2,288.9 | $ 2,277.4 |

See accompanying notes to condensed consolidated financial statements.

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**DCP MIDSTREAM PARTNERS, LP**
**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**
**(Unaudited)**

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| Operating revenues: | | |
| Sales of natural gas, propane, NGLs and condensate | $ 270.5 | $ 358.2 |
| Sales of natural gas, propane, NGLs and condensate to affiliates | 216.6 | 276.9 |
| Transportation, processing and other | 32.8 | 33.8 |
| Transportation, processing and other to affiliates | 11.0 | 5.2 |
| Losses from commodity derivative activity, net | (9.0) | (39.1) |
| Gains (losses) from commodity derivative activity, net — affiliates | 3.7 | (1.1) |
| Total operating revenues | 525.6 | 633.9 |
| Operating costs and expenses: | | |
| Purchases of natural gas, propane and NGLs | 294.2 | 409.3 |
| Purchases of natural gas, propane and NGLs from affiliates | 137.0 | 152.8 |
| Operating and maintenance expense | 26.3 | 28.6 |
| Depreciation and amortization expense | 25.2 | 24.3 |
| General and administrative expense | 4.6 | 4.4 |
| General and administrative expense — affiliates | 7.3 | 7.3 |
| Other income | (0.1) | (0.1) |
| Total operating costs and expenses | 494.5 | 626.6 |
| Operating income | 31.1 | 7.3 |
| Interest expense | (12.6) | (8.0) |
| Earnings from unconsolidated affiliates | 5.7 | 4.5 |
| Income before income taxes | 24.2 | 3.8 |
| Income tax expense | (0.2) | (0.3) |
| Net income | 24.0 | 3.5 |
| Net income attributable to noncontrolling interests | (0.7) | (3.5) |
| Net income attributable to partners | 23.3 | — |
| Net income attributable to predecessor operations | (2.6) | (5.9) |
| General partner's interest in net income | (8.4) | (5.5) |
| Net income (loss) allocable to limited partners | $ 12.3 | $ (11.4) |
| Net income (loss) per limited partner unit — basic | $ 0.26 | $ (0.28) |
| Net income (loss) per limited partner unit — diluted | $ 0.26 | $ (0.28) |
| Weighted-average limited partner units outstanding — basic | 46.9 | 41.3 |
| Weighted-average limited partner units outstanding — diluted | 47.0 | 41.3 |

See accompanying notes to condensed consolidated financial statements.

**DCP MIDSTREAM PARTNERS, LP**
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(Unaudited)**

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| Net income | $ 24.0 | $ 3.5 |
| Other comprehensive income: | | |
| Reclassification of cash flow hedges into earnings | 5.3 | 5.3 |
| Net unrealized gains (losses) on cash flow hedges | 0.3 | (0.9) |
| Total other comprehensive income | 5.6 | 4.4 |
| Total comprehensive income | 29.6 | 7.9 |
| Total comprehensive income attributable to noncontrolling interests | (0.7) | (3.5) |
| Total comprehensive income attributable to partners | $ 28.9 | $ 4.4 |

See accompanying notes to condensed consolidated financial statements.

**DCP MIDSTREAM PARTNERS, LP**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(Unaudited)**

| | Three Months Ended March 31, | |
|---|---|---|
| | 2012 | 2011 |
| | (Millions) | |
| OPERATING ACTIVITIES: | | |
| Net income | $ 24.0 | $ 3.5 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization expense | 25.2 | 24.3 |
| Earnings from unconsolidated affiliates | (5.7) | (4.5) |
| Distributions from unconsolidated affiliates | 5.6 | 5.6 |
| Net unrealized losses on derivative instruments | 23.8 | 35.1 |
| Other, net | 0.4 | 2.0 |
| Change in operating assets and liabilities, which provided (used) cash net of effects of acquisitions: | | |
| Accounts receivable | 55.1 | 29.3 |
| Inventories | 19.0 | 27.8 |
| Accounts payable | (75.7) | (29.0) |
| Accrued interest | 2.8 | 2.0 |
| Other current assets and liabilities | (12.6) | (1.3) |
| Other long-term assets and liabilities | (0.9) | (2.1) |
| Net cash provided by operating activities | 61.0 | 92.7 |
| INVESTING ACTIVITIES: | | |
| Capital expenditures | (53.4) | (33.1) |
| Acquisitions, net of cash acquired | (311.4) | (37.2) |
| Acquisition of unconsolidated affiliate | — | (114.2) |
| Investments in unconsolidated affiliates | (1.5) | (0.1) |
| Return of investment from unconsolidated affiliate | 1.0 | — |
| Proceeds from sale of assets | 0.1 | 0.2 |
| Net cash used in investing activities | (365.2) | (184.4) |
| FINANCING ACTIVITIES: | | |
| Proceeds from debt | 722.4 | 547.0 |
| Payments of debt | (604.0) | (519.0) |
| Payment of deferred financing costs | (2.7) | (0.1) |
| Excess purchase price over acquired assets | — | (35.7) |
| Proceeds from issuance of common units, net of offering costs | 234.2 | 139.7 |
| Net change in advances to predecessor from DCP Midstream, LLC | (11.5) | (7.2) |
| Distributions to unitholders and general partner | (36.7) | (30.1) |
| Distributions to noncontrolling interests | (1.7) | (5.4) |
| Contributions from DCP Midstream, LLC | 2.7 | 2.9 |
| Net cash provided by financing activities | 302.7 | 92.1 |
| Net change in cash and cash equivalents | (1.5) | 0.4 |
| Cash and cash equivalents, beginning of period | 7.6 | 6.7 |
| Cash and cash equivalents, end of period | $ 6.1 | $ 7.1 |

See accompanying notes to condensed consolidated financial statements.

**DCP MIDSTREAM PARTNERS, LP**
**CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY**
**(Unaudited)**

| | Partner's Equity | | | | | |
|---|---|---|---|---|---|---|
| | Predecessor Equity | Common Unitholders | General Partner | Accumulated Other Comprehensive (Loss) Income | Noncontrolling Interests | Total Equity |
| | (Millions) | | | | | |
| **Balance, January 1, 2012** | $ 257.4 | $ 654.4 | $ (4.7) | $ (21.2) | $ 212.4 | $1,098.3 |
| Net change in parent advances | (11.5) | — | — | — | — | (11.5) |
| Acquisition of additional 66.67% interest in Southeast Texas and NGL Hedge | (247.9) | 39.5 | — | — | — | (208.4) |
| Acquisition of additional 49.9% interest in East Texas | — | — | — | — | (175.8) | (175.8) |
| Issuance of units for Southeast Texas | — | 48.0 | — | — | — | 48.0 |
| Issuance of units for East Texas | — | 33.0 | — | — | — | 33.0 |
| Deficit purchase price under carrying value of acquired net assets | — | 54.0 | — | (4.2) | — | 49.8 |
| Issuance of 5,148,500 common units | — | 234.0 | — | — | — | 234.0 |
| Equity-based compensation | — | (0.8) | — | — | — | (0.8) |
| Distributions to unitholders and general partner | — | (29.6) | (7.1) | — | — | (36.7) |
| Distributions to noncontrolling interests | — | — | — | — | (1.7) | (1.7) |
| Contributions from DCP Midstream, LLC | — | 2.7 | — | — | — | 2.7 |
| Comprehensive income (loss): | | | | | | |
| Net income attributable to predecessor operations | 2.6 | — | — | — | — | 2.6 |
| Net income | — | 12.3 | 8.4 | — | 0.7 | 21.4 |
| Reclassification of cash flow hedges into earnings | — | — | — | 5.3 | — | 5.3 |
| Net unrealized losses on cash flow hedges | (0.6) | — | — | 0.9 | — | 0.3 |
| Total comprehensive income | 2.0 | 12.3 | 8.4 | 6.2 | 0.7 | 29.6 |
| **Balance, March 31, 2012** | $ — | $ 1,047.5 | $ (3.4) | $ (19.2) | $ 35.6 | $1,060.5 |

**DCP MIDSTREAM PARTNERS, LP**
**CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY**
**(Unaudited)**

| | Partner's Equity | | | | | |
|---|---|---|---|---|---|---|
| | Predecessor Equity | Common Unitholders | General Partner | Accumulated Other Comprehensive (Loss) Income | Noncontrolling Interests | Total Equity |
| | (Millions) | | | | | |
| **Balance, January 1, 2011** | $ 337.8 | $ 552.2 | $ (6.4) | $ (27.7) | $ 220.1 | $1,076.0 |
| Net change in parent advances | (2.9) | — | — | — | — | (2.9) |
| Acquisition of Southeast Texas | (114.3) | — | — | — | — | (114.3) |
| Excess purchase price over acquired assets | — | (35.7) | — | — | — | (35.7) |
| Issuance of 3,596,636 common units | — | 139.6 | — | — | — | 139.6 |
| Equity-based compensation | — | 1.9 | — | — | — | 1.9 |
| Distributions to DCP Midstream, LLC | — | (2.6) | — | — | — | (2.6) |
| Distributions to unitholders and general partner | — | (25.0) | (5.1) | — | — | (30.1) |
| Distributions to noncontrolling interests | — | — | — | — | (5.4) | (5.4) |
| Contributions from DCP Midstream, LLC | — | — | — | — | 2.9 | 2.9 |
| Comprehensive income (loss): | | | | | | |
| Net income attributable to predecessor operations | 5.9 | — | — | — | — | 5.9 |
| Net income | — | (11.4) | 5.5 | — | 3.5 | (2.4) |
| Reclassification of cash flow hedges into earnings | — | — | — | 5.3 | — | 5.3 |
| Net unrealized losses on cash flow hedges | — | — | — | (0.9) | — | (0.9) |
| Total comprehensive (loss) income | 5.9 | (11.4) | 5.5 | 4.4 | 3.5 | 7.9 |
| **Balance, March 31, 2011** | $ 226.5 | $ 619.0 | $ (6.0) | $ (23.3) | $ 221.1 | $1,037.3 |

See accompanying notes to condensed consolidated financial statements.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**
**(Unaudited)**

**1. Description of Business and Basis of Presentation**

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we or our or the Partnership, is engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; and producing, fractionating, transporting, storing and selling NGLs and condensate.

We are a Delaware limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our natural gas services business (which includes our Northern Louisiana system; our Southern Oklahoma system; our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery; our Wyoming system; a 75% interest in Collbran Valley Gas Gathering, LLC, or Collbran or our Colorado system; DCP East Texas Holdings, LLC, or our East Texas system (of which 49.9% was acquired in January 2012); our Michigan system; DCP Southeast Texas Holdings, GP, or our Southeast Texas system (of which 33.33% and 66.67% were acquired in January 2011 and March 2012, respectively), our NGL logistics business (which includes the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, the NGL storage facility in Michigan and the DJ Basin NGL Fractionators in Colorado), and our wholesale propane logistics business.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, and is wholly-owned by DCP Midstream, LLC. As of March 31, 2011, DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, was owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. During the third quarter of 2011, ConocoPhillips announced plans to separate its business into two stand-alone publicly traded companies, and completed the separation in May 2012. As a result of this transaction, DCP Midstream, LLC is no longer owned 50% by ConocoPhillips. ConocoPhillips' 50% ownership interest in DCP Midstream, LLC has been transferred to the new downstream company, Phillips 66. We do not anticipate that the change in ownership will have a material impact on our business or operations. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates' employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 27% of us.

The condensed consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries in which we have the ability to exercise control and our undivided interests in jointly owned assets. Investments in greater than 20% owned affiliates that are not variable interest entities and in which we do not have the ability to exercise control, and investments in less than 20% owned affiliates in which we have the ability to exercise significant influence, are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

Our predecessor operations consist of our initial 33.33% interest in Southeast Texas, which we acquired from DCP Midstream, LLC in January 2011, and the remaining 66.67% interest in Southeast Texas and commodity derivative instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012. Prior to our acquisition of the remaining 66.67% interest in Southeast Texas, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method. Subsequent to this transaction, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. These transfers of net assets between entities under common control were accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements include the historical results of our 100% interest in Southeast Texas and the natural gas commodity derivatives associated with the storage business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. The amount of the purchase price in excess or in deficit of DCP Midstream, LLC's basis in the net assets is recognized as a reduction or an addition to partners' equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates. All intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the condensed consolidated financial statements as transactions between affiliates.

The accompanying unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission, or SEC. Accordingly, these condensed consolidated financial statements reflect all adjustments, consisting only of normal recurring adjustments, that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and notes normally included in our annual financial statements have been condensed or omitted from these interim financial statements pursuant to such rules and regulations. Results of operations for the three months ended March 31, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. These condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and notes thereto included in our 2011 Annual Report on Form 10-K.

## 2. Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-04 "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs",* or ASU 2011-04** — In May 2011, the FASB issued ASU 2011-04 which amends Accounting Standards Codification, Topic 820 "Fair Value Measurements and Disclosures" to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB's intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 became effective for us for interim and annual periods beginning after December 15, 2011. The provisions of ASU 2011-04 impact only disclosures, and we have disclosed information in accordance with the provisions of ASU 2011-04 within this filing.

## 3. Acquisitions

On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. $192.0 million of the aggregate purchase price was financed with a portion of the net proceeds from our 4.95% 10-year Senior Notes offering. The remaining $48.0 million consideration was financed by the issuance at closing of an aggregate of 1,000,417 of our common units. DCP Midstream, LLC also provided fixed price NGL commodity derivatives, valued at $39.5 million, for the three year period subsequent to closing the newly acquired interest. The $29.6 million deficit purchase price under the historical basis of the net assets acquired and the $48.0 million of common units issued as consideration for this acquisition were recorded as an increase in common unitholders equity. Prior to the acquisition of the additional interest in Southeast Texas, we owned a 33.33% interest which we accounted for as an unconsolidated affiliate using the equity method. The acquisition of the remaining 66.67% interest in Southeast Texas represents a transaction between entities under common control and a change in reporting entity. Accordingly, our consolidated financial statements have been adjusted to retrospectively include the historical results of our 100% interest in Southeast Texas and the natural gas commodity derivatives associated with the storage business for all periods presented, similar to the pooling method.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

***Combined Financial Information***

The results of our 100% interest in Southeast Texas are included in the condensed consolidated balance sheets as of March 31, 2012 and December 31, 2011. The following table presents the previously reported December 31, 2011 condensed consolidated balance sheet, adjusted for the acquisition of the remaining 66.67% interest in Southeast Texas from DCP Midstream, LLC:

**As of December 31, 2011**

| | DCP Midstream Partners, LP (As previously reported) (a) | Consolidate Southeast Texas (b) | Remove Southeast Texas Investment in Unconsolidated Affiliate(c) | Combined DCP Midstream Partners, LP (As currently reported) |
|---|---|---|---|---|
| | (Millions) | | | |
| **ASSETS** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $ 6.7 | $ 0.9 | $ — | $ 7.6 |
| Accounts receivable | 161.4 | 53.4 | — | 214.8 |
| Inventories | 64.7 | 23.2 | — | 87.9 |
| Other | 7.1 | 36.3 | — | 43.4 |
| Total current assets | 239.9 | 113.8 | — | 353.7 |
| Property, plant and equipment, net | 1,181.8 | 317.6 | — | 1,499.4 |
| Goodwill and intangible assets, net | 255.8 | 43.3 | — | 299.1 |
| Investments in unconsolidated affiliates | 208.7 | — | (101.6) | 107.1 |
| Other non-current assets | 17.4 | 0.7 | — | 18.1 |
| Total assets | $ 1,903.6 | $ 475.4 | $ (101.6) | $ 2,277.4 |
| **LIABILITIES AND EQUITY** | | | | |
| Accounts payable and other current liabilities | $ 269.2 | $ 111.3 | $ — | $ 380.5 |
| Long-term debt | 746.8 | — | — | 746.8 |
| Other long-term liabilities | 46.7 | 5.1 | — | 51.8 |
| Total liabilities | 1,062.7 | 116.4 | — | 1,179.1 |
| Commitments and contingent liabilities | | | | |
| Equity: | | | | |
| Partners' equity | | | | |
| Net equity | 649.7 | 360.8 | (103.4) | 907.1 |
| Accumulated other comprehensive income | (21.2) | (1.8) | 1.8 | (21.2) |
| Total partners' equity | 628.5 | 359.0 | (101.6) | 885.9 |
| Noncontrolling interests | 212.4 | — | — | 212.4 |
| Total equity | 840.9 | 359.0 | (101.6) | 1,098.3 |
| Total liabilities and equity | $ 1,903.6 | $ 475.4 | $ (101.6) | $ 2,277.4 |

(a) Amounts as previously reported with 33.33% of Southeast Texas' results presented as investments in unconsolidated affiliates.
(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.
(c) Adjustments to remove Southeast Texas 33.33% investment in unconsolidated affiliates.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

The results of our 100% interest in Southeast Texas are included in the condensed consolidated statements of operations for the three months ended March 31, 2012 and 2011. The following table presents the previously reported condensed consolidated statements of operations for the three months ended March 31, 2011, adjusted for the acquisition of the remaining 66.67% interest in Southeast Texas from DCP Midstream, LLC:

**Three Months Ended March 31, 2011**

| | DCP Midstream Partners, LP (As previously reported) (a) | Consolidate Southeast Texas (b) | Remove Southeast Texas Equity Earnings (c) | Combined DCP Midstream Partners, LP (As currently reported) |
|---|---|---|---|---|
| | | (Millions) | | |
| Operating revenues: | | | | |
| Sales of natural gas, propane, NGLs and condensate | $ 429.7 | $ 205.4 | $ — | $ 635.1 |
| Transportation, processing and other | 35.6 | 3.4 | — | 39.0 |
| Losses from commodity derivative activity, net | (40.2) | — | — | (40.2) |
| Total operating revenues | 425.1 | 208.8 | — | 633.9 |
| Operating costs and expenses: | | | | |
| Purchases of natural gas, propane and NGLs | 375.0 | 187.1 | — | 562.1 |
| Operating and maintenance expense | 24.1 | 4.5 | — | 28.6 |
| Depreciation and amortization expense | 19.9 | 4.4 | — | 24.3 |
| General and administrative expense | 9.0 | 2.7 | — | 11.7 |
| Other income | (0.1) | — | — | (0.1) |
| Total operating costs and expenses | 427.9 | 198.7 | — | 626.6 |
| Operating (loss) income | (2.8) | 10.1 | — | 7.3 |
| Interest expense, net | (8.0) | — | — | (8.0) |
| Earnings from unconsolidated affiliates | 8.6 | — | (4.1) | 4.5 |
| (Loss) income before income taxes | (2.2) | 10.1 | (4.1) | 3.8 |
| Income tax expense | (0.2) | (0.1) | — | (0.3) |
| Net (loss) income | (2.4) | 10.0 | (4.1) | 3.5 |
| Net income attributable to noncontrolling interests | (3.5) | — | — | (3.5) |
| Net (loss) income attributable to partners | $ (5.9) | $ 10.0 | $ (4.1) | $ — |

(a) Amounts as previously reported with 33.33% of Southeast Texas' results presented as earnings from unconsolidated affiliates.
(b) Adjustments to present Southeast Texas on a consolidated basis at 100% ownership, including commodity derivatives.
(c) Adjustments to remove Southeast Texas equity earnings at 33.33%.

The pro forma information is not intended to reflect actual results that would have occurred if the acquired business had been combined during the period presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC for aggregate consideration of $165.0 million, subject to certain working capital and other customary purchase price adjustments. $132.0 million of the aggregate purchase price was financed with the net proceeds from our Term Loan Agreement. The remaining $33.0 million consideration was financed by the issuance at closing of an aggregate of 727,520 of our common units. The $20.2 million deficit purchase price under the historical basis of the net assets acquired and the $33.0 million of common units issued as consideration for this acquisition were recorded as an increase in common unitholders equity. Prior to the contribution of the additional interest in East Texas, we owned a 50.1% interest which we accounted for as a consolidated subsidiary. The contribution of the remaining 49.9% interest in East Texas represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we have included the results of the remaining 49.9% interest in East Texas prospectively from the date of contribution.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

## 4. Agreements and Transactions with Affiliates

### DCP Midstream, LLC

***Omnibus Agreement and Other General and Administrative Charges***

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. In January 2012, in conjunction with our acquisition of the remaining 49.9% interest in East Texas, we increased the annual fee we pay to DCP Midstream, LLC by $7.4 million. In March 2012, in conjunction with our acquisition of the remaining 66.67% interest in Southeast Texas, we increased the annual fee we pay to DCP Midstream, LLC by $10.3 million, prorated for the remainder of the calendar year. These fees were previously allocated to East Texas and Southeast Texas. As a result of these transactions, the annual fee we pay to DCP Midstream, LLC will be $27.9 million.

Following is a summary of the fees we incurred under the Omnibus Agreement as well as other fees paid to DCP Midstream, LLC:

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| Omnibus Agreement | $ 4.4 | $ 2.5 |
| Other fees — DCP Midstream, LLC | 2.8 | 4.7 |
| Total — DCP Midstream, LLC | $ 7.2 | $ 7.2 |

In addition to the Omnibus Agreement, we incurred other general and administrative fees with DCP Midstream, LLC of $0.3 million, for each of the three months ended March 31, 2012 and 2011. These amounts include allocated expenses, including professional services, insurance and internal audit. For the three months ended March 31, 2012, Southeast Texas incurred $2.5 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012. For the three months ended March 31, 2011, East Texas incurred $1.9 million in general and administrative expenses directly from DCP Midstream, LLC.

***Other Agreements and Transactions with DCP Midstream, LLC***

DCP Midstream, LLC was a significant customer during the three months ended March 31, 2012 and 2011.

We sell a portion of our residue gas, NGLs and condensate to, purchase natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase from and sell commodities and services to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf. We have and may continue to enter into market based derivative transactions directly with DCP Midstream, LLC, whereby DCP Midstream is the counterparty.

We have a contractual arrangement with DCP Midstream, LLC, through March 2022, in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Southern Oklahoma system, which is part of our Natural Gas Services segment. In addition, in February 2010, a contract was signed with DCP Midstream, LLC providing for adjustments to those fees based upon plant efficiencies related to our portion of volumes from the Southern Oklahoma system being processed at DCP Midstream, LLC's plant through March 2022. We generally report fees associated with these activities in the condensed consolidated statements of operations as purchases of natural gas, propane, NGLs and condensate from affiliates. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation, processing and other to affiliates.

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system, included in our Northern Louisiana system, which is part of our Natural Gas Services segment, that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. We purchase natural gas from DCP Midstream, LLC upstream of Pelico and transport it to Pelico under an interruptible transportation agreement with an affiliate. Our purchases from DCP Midstream, LLC are at DCP Midstream, LLC's actual acquisition cost plus any transportation service charges. Volumes that exceed our on-system demand are sold to DCP Midstream, LLC at an index-based price, less contractually agreed to marketing fees. Revenues associated with these activities are reported gross in our condensed consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

In conjunction with our acquisitions of our East Texas system, which is part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on East Texas capital projects. These reimbursements are for certain capital projects which have commenced within three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $2.7 million and $2.9 million for the three months ended March 31, 2012 and 2011, respectively.

In our Natural Gas Services segment, we sell NGLs processed at certain of our plants, and sell condensate removed from the gas gathering systems that deliver to certain of our systems under contracts to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation, processing and other charges from the tailgate of the respective asset.

In our NGL Logistics segment, we also have a contractual arrangement with a subsidiary of DCP Midstream, LLC which provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

In conjunction with our Wattenberg pipeline and effective January 1, 2011, we entered into a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC's processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenues under our tariff. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

We pay a fee to DCP Midstream, LLC to operate our DJ Basin NGL Fractionators and receive fees for the processing of DCP Midstream, LLC's committed NGLs produced by them in Weld County, Colorado at our DJ Basin NGL Fractionators under agreements that are effective through March 2018. During the three months ended March 31, 2012 we incurred fees of $0.2 million, which are included in operating and maintenance expense in the consolidated statements of operations.

DCP Midstream, LLC has issued parental guarantees, totaling $70.0 million as of March 31, 2012, in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream, LLC a fee of 0.5% per annum on these outstanding guarantees.

On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC. DCP Midstream, LLC previously issued parental guarantees for its 49.9% limited liability company interest in East Texas. As of March 31, 2012, parental guarantees totaling $5.0 million remained outstanding. These guarantees terminated in April 2012.

**Spectra Energy**

We had propane supply agreements with Spectra Energy, effective through April 2012, which provided us propane supply at our marine terminals, which were included in our Wholesale Propane Logistics segment, for up to approximately 185 million gallons of propane annually. We have contracted with marine import suppliers in the past and will continue to secure optimal supply sources in the future as part of a diversified supply portfolio.

**ConocoPhillips**

We have multiple agreements with ConocoPhillips and its affiliates. The agreements include fee-based and percent-of-proceeds gathering and processing arrangements, and gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell to ConocoPhillips and its affiliates in the ordinary course of business.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

**Summary of Transactions with Affiliates**

The following table summarizes transactions with affiliates:

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| DCP Midstream, LLC: | | |
| Sales of natural gas, propane, NGLs and condensate | $ 209.2 | $ 265.4 |
| Transportation, processing and other | $ 9.2 | $ 3.2 |
| Purchases of natural gas, propane and NGLs | $ 59.9 | $ 63.0 |
| Gains from commodity derivative activity, net | $ 3.7 | $ (1.0) |
| General and administrative expense | $ 7.2 | $ 7.2 |
| Interest expense | $ — | $ — |
| Spectra Energy: | | |
| Purchases of natural gas, propane and NGLs | $ 73.7 | $ 85.2 |
| ConocoPhillips: | | |
| Sales of natural gas, propane, NGLs and condensate | $ 7.4 | $ 11.5 |
| Transportation, processing and other | $ 1.8 | $ 2.0 |
| Purchases of natural gas, propane and NGLs | $ 1.0 | $ 1.5 |
| General and administrative expense | $ 0.1 | $ 0.1 |
| Unconsolidated affiliates: | | |
| Purchases of natural gas, propane and NGLs | $ 2.4 | $ 3.1 |

We had balances with affiliates as follows:

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| DCP Midstream, LLC: | | |
| Accounts receivable | $ 103.4 | $ 100.0 |
| Accounts payable | $ 35.8 | $ 22.6 |
| Unrealized gains on derivative instruments — current | $ 34.4 | $ 0.6 |
| Unrealized gains on derivative instruments — long-term | $ 27.3 | $ — |
| Unrealized losses on derivative instruments — current | $ (13.0) | $ (0.6) |
| Unrealized losses on derivative instruments — long-term | $ (3.8) | $ — |
| Spectra Energy: | | |
| Accounts receivable | $ 0.1 | $ 0.1 |
| Accounts payable | $ 2.4 | $ 21.4 |
| ConocoPhillips: | | |
| Accounts receivable | $ 3.2 | $ 6.1 |
| Accounts payable | $ 0.3 | $ 0.4 |
| Unrealized gains on derivative instruments — current | $ — | $ 2.5 |
| Unrealized losses on derivative instruments — current | $ — | $ (2.0) |
| Unconsolidated affiliates: | | |
| Accounts payable | $ — | $ 2.4 |

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

## 5. Inventories

Inventories were as follows:

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (millions) | |
| Natural gas | $ 17.4 | $ 25.6 |
| NGLs | 51.6 | 62.3 |
| Total inventories | $ 69.0 | $ 87.9 |

## 6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

| | Depreciable Life | March 31, 2012 | December 31, 2011 |
|---|---|---|---|
| | | (Millions) | |
| Gathering and transmission systems | 15 — 30 Years | $1,198.3 | $ 1,191.9 |
| Processing, storage, and terminal facilities | 20 — 50 Years | 773.5 | 764.3 |
| Other | 0 — 30 Years | 21.6 | 21.6 |
| Construction work in progress | | 272.4 | 218.3 |
| Property, plant and equipment | | 2,265.8 | 2,196.1 |
| Accumulated depreciation | | (719.7) | (696.7) |
| Property, plant and equipment, net | | $1,546.1 | $ 1,499.4 |

Interest capitalized on construction projects for the three months ended March 31, 2012 and 2011 were $1.2 million and $0.2 million, respectively.

Depreciation expense was $23.1 million and $22.2 million for the three months ended March 31, 2012 and 2011, respectively.

***Asset Retirement Obligations*** — As of March 31, 2012, we had asset retirement obligations of $16.1 million included in other long-term liabilities in the condensed consolidated balance sheets. As of December 31, 2011, we had asset retirement obligations of $12.4 million included in other long-term liabilities in the condensed consolidated balance sheets. During the first quarter of 2012, we recorded a change in estimate to increase our asset retirement obligations by approximately $4.3 million. The change in estimate was primarily attributable to a reassessment of anticipated timing of settlements and of the original asset retirement obligation estimated amounts. For the three months ended March 31, 2012, accretion benefit was $0.6 million and for the three months ended March 31, 2011, accretion expense was $0.2 million.

## 7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill was as follows:

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| Beginning of period | $ 153.8 | $ 151.2 |
| Acquisitions | — | 2.6 |
| End of period | $ 153.8 | $ 153.8 |

The carrying value of goodwill as of March 31, 2012 and December 31, 2011 was $82.2 million for each of the periods for our Natural Gas Services segment, $34.7 million for each of the periods for our NGL logistics segment, and $36.9 million for each of the periods for our Wholesale Propane Logistics segment.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and were as follows:

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| Gross carrying amount | $ 164.3 | $ 164.3 |
| Accumulated amortization | (21.1) | (19.0) |
| Intangible assets, net | $ 143.2 | $ 145.3 |

For each of the three months ended March 31, 2012 and 2011, we recorded amortization expense of $2.1 million. As of March 31, 2012, the remaining amortization periods ranged from approximately 10 years to 23 years, with a weighted-average remaining period of approximately 18 years.

Estimated future amortization for these intangible assets is as follows:

| Estimated Future Amortization | |
|---|---|
| (Millions) | |
| Remainder of 2012 | $ 6.3 |
| 2013 | 8.4 |
| 2014 | 8.4 |
| 2015 | 8.4 |
| 2016 | 8.4 |
| Thereafter | 103.3 |
| Total | $143.2 |

## 8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

| | Percentage of Ownership as of March 31, 2012 and December 31, 2011 | Carrying Value as of March 31, 2012 | Carrying Value as of December 31, 2011 |
|---|---|---|---|
| | | (Millions) | |
| Discovery Producer Services LLC | 40% | $ 108.3 | $ 106.9 |
| Other | 50% | 0.2 | 0.2 |
| Total investments in unconsolidated affiliates | | $ 108.5 | $ 107.1 |

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $32.0 million and $32.6 million at March 31, 2012 and December 31, 2011, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

Earnings from investments in unconsolidated affiliates were as follows:

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| Discovery Producer Services LLC | $ 5.7 | $ 4.5 |
| Total earnings from unconsolidated affiliates | $ 5.7 | $ 4.5 |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

The following summarizes combined financial information of our investments in unconsolidated affiliates:

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| Statements of operations: | | |
| Operating revenue | $ 47.2 | $ 50.7 |
| Operating expenses | $ 34.7 | $ 40.9 |
| Net income | $ 12.7 | $ 9.8 |

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| Balance sheets: | | |
| Current assets | $ 34.8 | $ 38.0 |
| Long-term assets | 390.2 | 360.7 |
| Current liabilities | (44.7) | (21.1) |
| Long-term liabilities | (29.1) | (28.5) |
| Net assets | $ 351.2 | $ 349.1 |

## 9. Fair Value Measurement

***Determination of Fair Value***

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.
- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 11 Risk Management and Hedging Activities.

***Valuation Hierarchy***

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

***Commodity Derivative Assets and Liabilities***

We enter into a variety of derivative financial instruments, which may include over the counter, or OTC, instruments, such as natural gas, crude oil or NGL contracts.

Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

***Interest Rate Derivative Assets and Liabilities***

We use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our existing floating rate debt for fixed-rate debt. Our swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and entity valuation adjustments in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

***Nonfinancial Assets and Liabilities***

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3, in the event that we were required to measure and record such assets at fair value within our condensed consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

We utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

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The following table presents the financial instruments carried at fair value as of March 31, 2012 and December 31, 2011, by consolidated balance sheet caption and by valuation hierarchy as described above:

| | March 31, 2012 | | | | December 31, 2011 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Carrying Value | Level 1 | Level 2 | Level 3 | Total Carrying Value |
| | (Millions) | | | | | | | |
| Current assets: | | | | | | | | |
| Commodity derivatives (a) | $ — | $ 23.6 | $ 14.6 | $ 38.2 | $ — | $ 40.1 | $ 1.1 | $ 41.2 |
| Long-term assets: | | | | | | | | |
| Commodity derivatives (b) | $ — | $ 3.3 | $ 27.9 | $ 31.2 | $ — | $ 5.4 | $ 1.0 | $ 6.4 |
| Current liabilities (c): | | | | | | | | |
| Commodity derivatives | $ — | $ (42.7) | $ (2.6) | $ (45.3) | $ — | $ (43.1) | $ (0.7) | $ (43.8) |
| Interest rate derivatives | $ — | $ (7.3) | $ — | $ (7.3) | $ — | $ (16.1) | $ — | $ (16.1) |
| Long-term liabilities (d): | | | | | | | | |
| Commodity derivatives | $ — | $ (31.8) | $ (0.4) | $ (32.2) | $ — | $ (27.5) | $ (0.3) | $ (27.8) |
| Interest rate derivatives | $ — | $ (4.3) | $ — | $ (4.3) | $ — | $ (5.0) | $ — | $ (5.0) |

(a) Included in current unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(b) Included in long-term unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(c) Included in current unrealized losses on derivative instruments in our condensed consolidated balance sheets.
(d) Included in long-term unrealized losses on derivative instruments in our condensed consolidated balance sheets.

***Changes in Levels 1 and 2 Fair Value Measurements***

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. In the event that there is a movement between the classification of an instrument as Level 1 or 2, the transfer between Level 1 and Level 2 would be reflected in a table as Transfers in/out of Level 1/Level 2. During the three months ended March 31, 2012, there were no transfers between Level 1 and Level 2 of the fair value hierarchy.

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***Changes in Level 3 Fair Value Measurements***

The tables below illustrate a rollforward of the amounts included in our condensed consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. The significant unobservable inputs used in determining fair value include adjustments by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the "Transfers in/out of Level 3" caption.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

| | Commodity Derivative Instruments | | | |
|---|---|---|---|---|
| | Current Assets | Long-Term Assets | Current Liabilities | Long-Term Liabilities |
| | (Millions) | | | |
| **Three months ended March 31, 2012 (a):** | | | | |
| Beginning balance | $ 1.1 | $ 1.0 | $ (0.7) | $ (0.3) |
| Net realized and unrealized losses included in earnings (d) | 1.0 | 0.2 | (1.7) | (0.1) |
| Transfers into Level 3 (c) | — | — | — | — |
| Transfers out of Level 3 (c) | — | — | — | — |
| Settlements | (0.3) | — | 0.2 | — |
| Purchases | 12.8 | 26.7 | (0.4) | — |
| Ending balance | $ 14.6 | $27.9 | $ (2.6) | $ (0.4) |
| Net unrealized losses still held included in earnings (d) | $ 1.0 | $ 0.3 | $ (2.0) | $ (0.1) |
| **Three months ended March 31, 2011 (b):** | | | | |
| Beginning balance | $ 0.3 | $ 0.3 | $ (0.1) | $ (0.5) |
| Net realized and unrealized (losses) gains included in earnings (d) | — | (0.1) | (2.2) | (1.9) |
| Transfers into Level 3 (c) | — | — | — | — |
| Transfers out of Level 3 (c) | — | — | — | — |
| Settlements | (0.1) | — | — | — |
| Ending balance | $ 0.2 | $ 0.2 | $ (2.3) | $ (2.4) |
| Net unrealized gains still held included in earnings (d) | $ — | $ (0.1) | $ (2.2) | $ (1.9) |

(a) There were no issuances and sales for the three months ended March 31, 2012.
(b) There were no purchases, issuances and sales for the three months ended March 31, 2011.
(c) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period. We had no transfers into and out of Level 3.
(d) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains or losses relating to assets and liabilities classified as Level 3.

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***Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs***

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending our short or long position in contracts.

| Product Group | Fair Value (Millions) | Forward Curve Range | |
|---|---|---|---|
| **Assets** | | | |
| NGL's | $40.0 | $0.38-$2.38 | Per gallon |
| Natural Gas | $2.5 | $3.09-$4.20 | Per MMBtu |
| **Liabilities** | | | |
| NGL's | $(2.2) | $1.23-$2.38 | Per gallon |
| Natural Gas | $(0.8) | $3.30-$4.20 | Per MMBtu |

***Estimated Fair Value of Financial Instruments***

Valuation of a contract's fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

The fair value of our interest rate swaps and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The "prices supported by quoted market prices and other external sources" category includes our interest rate swaps, our NYMEX positions in natural gas, NGLs and crude oil. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes "strip" transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The "prices based on models and other valuation methods" category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on derivative instruments are carried at fair value. Each of the carrying and fair values of outstanding balances under our Credit Agreement are $267.0 million as of March 31, 2012, and $497.0 million as of December 31, 2011. The carrying and fair values of the 4.95% Senior Notes are $350.0 million and $351.7 million, respectively, as of March 31, 2012. The carrying and fair values of the 3.25% Senior Notes are $250.0 million and $252.2 million as of March 31, 2012. The carrying value of the 3.25% Senior Notes as of December 31, 2011 was $250.0 million, which approximated fair value. We determine the fair value of our credit facility borrowings based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy.

## 10. Debt

Long-term debt was as follows:

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| ***Credit Agreement*** | | |
| Revolving credit facility, weighted-average variable interest rate of 1.56% and 1.69%, respectively, and net effective interest rate of 3.97% and 4.86%, respectively, due November 10, 2016 (a) | $ 267.0 | $ 497.0 |
| ***Debt Securities*** | | |
| Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022 | 350.0 | — |
| Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015 | 250.0 | 250.0 |
| Unamortized discount | (1.8) | (0.2) |
| Total long-term debt | $ 865.2 | $ 746.8 |

(a) This debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.94% to 5.19%, for a net effective rate of 3.97% on the $267.0 million of outstanding debt under our revolving credit facility as of March 31, 2012.

***Credit Agreement***

We have a $1.0 billion revolving credit facility that matures November 10, 2016, or the Credit Agreement.

At March 31, 2012 and December 31, 2011, we had $1.1 million of letters of credit issued and outstanding under the Credit Agreement. As of March 31, 2012, the unused capacity under the revolving credit facility was $731.9 million, of which approximately $591.1 million was available for general working capital purposes.

Our borrowing capacity is limited at March 31, 2012 by the Credit Agreement’s financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the November 10, 2016 maturity date.

Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) LIBOR, plus an applicable margin ranging from 0.85% to 1.65% depending on our credit rating; or (2)(a) the base rate which shall be the higher of Wells Fargo Bank N.A.’s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin ranging from 0% to 0.65% depending on our credit rating. The revolving credit facility incurs an annual facility fee of 0.15% to 0.35% depending on our credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

The Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 to 1.0.

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***Debt Securities***

On March 13, 2012, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, which are net of underwriters' fees, related expenses and unamortized discounts of $2.3 million, $0.3 million and $1.6 million, respectively, which we used to fund a portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2012. The notes will mature on April 1, 2022, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

On September 30, 2010, we issued $250.0 million of 3.25% 5-year Senior Notes due October 1, 2015. We received proceeds of $247.7 million, which are net of underwriters' fees, related expenses and unamortized discounts of $1.5 million, $0.6 million and $0.2 million, respectively, which we used to repay funds borrowed under the revolver portion of our Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing April 1, 2011. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

Both series of notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Credit Facility. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

***Term Loan Agreement***

On January 3, 2012, we entered into a 2-year Term Loan Agreement with Wells Fargo Bank, National Association, SunTrust Bank and The Bank of Tokyo-Mitsubishi UFJ, Ltd. as lenders. We borrowed $135.0 million under the term loan on January 3, 2012, which was used to fund a portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

***Other Agreements***

As of March 31, 2012, we had a contingent letter of credit for up to $10.0 million, on which we pay a fee of 0.50% per annum. This facility reduces the amount of cash we may be required to post as collateral. As of March 31, 2012, we had no letters of credit issued on this facility. Any letters of credit issued on this facility will incur a fee of 1.75% per annum and will not reduce the available capacity under our credit facility.

The future maturities of long-term debt in the year indicated are as follows:

| | Debt Maturities (Millions) |
|---|---|
| 2011 | $ — |
| 2012 | — |
| 2013 | — |
| 2014 | — |
| 2015 | 250.0 |
| Thereafter | 617.0 |
| Unamortized discount | (1.8) |
| Total | $ 865.2 |

## 11. Risk Management and Hedging Activities

Our day-to-day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with both physical and financial transactions. We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following briefly describes each of the risks that we manage.

### Commodity Price Risk

***Cash Flow Protection Activities*** — We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering, processing and storage services, we may receive cash or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2016 with commodity derivative instruments. Given the limited liquidity and tenor of the NGL derivatives market, we have primarily utilized crude oil swaps and costless collars to mitigate a portion of our commodity price exposure for NGLs. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. Historically, prices of NGLs have been generally related to the price of crude oil, with some exceptions, notably in late 2008 to early 2009, when NGL pricing was at a greater discount to crude oil pricing. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Our crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange our floating price risk for a fixed price. We also utilize crude oil costless collars that minimize our floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our consolidated statements of operations as a gain or a loss on commodity derivative activity.

Our Wholesale Propane Logistics segment is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. However, to the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and any change in fair value is reflected in the current period within our condensed consolidated statements of operations as a gain or loss on commodity derivative activity.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting, whereby changes in fair value are recorded directly to the condensed consolidated statements of operations; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting.

***Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program*** — Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

***Commodity Cash Flow Hedges*** — On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business.

During 2011, Southeast Texas commenced an expansion project to build an additional storage cavern. Upon completion of the expansion project, Southeast Texas will be required to purchase a significant amount of base gas to bring the storage cavern to operation. To mitigate risk associated with this forecasted purchase of natural gas, Southeast Texas executed a series of derivative financial instruments, which have been designated as cash flow hedges. These cash flow hedges were in a loss position of $3.5 million as of March 31, 2012 and will fluctuate in value through the term of construction. Any effective changes in fair value of these derivative instruments will be deferred in AOCI until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, following completion of the additional storage cavern, any deferred gain or loss at the time of the purchase will remain in AOCI until the cavern is emptied and the base gas is sold.

In order for storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our condensed consolidated balance sheets as a component of property, plant and equipment, net. To mitigate the risk associated with the forecasted re-purchase of base gas, in 2008 we executed a series of derivative financial instruments, which were designated as cash flow hedges. The cash paid upon settlement of these hedges economically offsets the cash paid to purchase the base gas. As a result, a deferred loss of $2.7 million was recognized and will remain in AOCI until such time that our cavern is emptied and the base gas is sold.

**Interest Rate Risk**

We mitigate a portion of our interest rate risk with interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2011, we had interest rate swap agreements totaling $450.0 million, of which we had designated $425.0 million as cash flow hedges and accounted for the remaining $25.0 million under the mark-to-market method of accounting. In March 2012, we paid down a portion of the revolving credit facility and, as a result, we discontinued cash flow hedge accounting on $225.0 million of our interest rate swap agreements.

At March 31, 2012, we had interest rate swap agreements totaling $450.0 million, of which we have designated $200.0 million as cash flow hedges and account for the remaining $250.0 million under the mark-to-market method of accounting. $450.0 million of these agreements extend through June 2012, with $150.0 million extending through June 2014. Based on our current operations we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt.

Effectiveness of our interest rate swap agreements designated as cash flow hedges is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings.

At March 31, 2012, $275.0 million of the interest rate swap agreements reprice prospectively approximately every 90 days and the remaining $175.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed-rates ranging from 2.94% to 5.19%, and receive interest payments based on the three-month and one-month LIBOR.

On March 8, 2012, we settled $195.0 million of our forward-starting interest rate swap agreements for $6.6 million. The net deferred losses of $5.1 million in AOCI, as of the settlement date, will be amortized into interest expense associated with our long-term debt offering through 2022.

**Contingent Credit Features**

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an effective event of default under our Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- In the event that we or DCP Midstream, LLC were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Credit Agreement. As of March 31, 2012, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of March 31, 2012, we had $59.4 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of March 31, 2012, if a credit-risk related event were to occur we may be required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of March 31, 2012, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $53.5 million.

As of March 31, 2012, we had $11.6 million of individual interest rate swap instruments that were in a net liability position and were subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our Credit Agreement that occurs and is continuing, the counterparties to our swap instruments have the right to request that we net settle the instrument in the form of cash.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

**Unconsolidated Affiliates**

Discovery Producer Services LLC, our unconsolidated affiliate, entered into agreements with a pipe vendor denominated in a foreign currency in connection with the planned expansion for the natural gas gathering pipeline system in the deepwater Gulf of Mexico, the Keathley Canyon Connector. Discovery entered into certain foreign currency derivative contracts to mitigate a portion of the foreign currency exchange risks which were designated as cash flow hedges. As these hedges are owned by Discovery, an unconsolidated affiliate, we include the impact to AOCI on our consolidated balance sheet.

**Collateral**

As of March 31, 2012, we had a contingent letter of credit facility for up to $10.0 million, on which we have no letters of credit issued. DCP Midstream, LLC had issued and outstanding parental guarantees totaling $70.0 million in favor of certain counterparties to our commodity derivative instruments. This contingent letter of credit facility and parental guarantees reduce the amount of cash we may be required to post as collateral. As of March 31, 2012, we had no cash collateral posted with counterparties to our commodity derivative instruments.

**Summarized Derivative Information**

The following summarizes the balance within AOCI relative to our commodity and interest rate cash flow hedges:

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| Commodity cash flow hedges: | | |
| Net deferred losses in AOCI | $ (6.2) | $ (1.8) |
| Interest rate cash flow hedges: | | |
| Net deferred losses in AOCI | (13.9) | (19.4) |
| Foreign currency cash flow hedges (a): | | |
| Net deferred losses in AOCI | 0.9 | — |
| Total AOCI | $ (19.2) | $ (21.2) |

(a) Relates to Discovery, our unconsolidated affiliate.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

The fair value of our derivative instruments that are designated as hedging instruments, those that are marked-to-market each period, as well as the location of each within our condensed consolidated balance sheets, by major category, is summarized as follows:

| Balance Sheet Line Item | March 31, 2012 | December 31, 2011 | Balance Sheet Line Item | March 31, 2012 | December 31, 2011 |
|---|---|---|---|---|---|
| | (Millions) | | | (Millions) | |
| **Derivative Assets Designated as Hedging Instruments:** | | | **Derivative Liabilities Designated as Hedging Instruments:** | | |
| **Commodity derivatives:** | | | **Commodity derivatives:** | | |
| Unrealized gains on derivative instruments — current | $ — | $ — | Unrealized losses on derivative instruments — current | $ — | $ — |
| Unrealized gains on derivative instruments — long-term | — | — | Unrealized losses on derivative instruments — long-term | (3.5) | (2.6) |
| | $ — | $ — | | $ (3.5) | $ (2.6) |
| **Interest rate derivatives:** | | | **Interest rate derivatives:** | | |
| Unrealized gains on derivative instruments — current | $ — | $ — | Unrealized losses on derivative instruments — current | $ (4.6) | $ (15.7) |
| Unrealized gains on derivative instruments — long-term | — | — | Unrealized losses on derivative instruments — long-term | (4.3) | (5.0) |
| | $ — | $ — | | $ (8.9) | $ (20.7) |
| **Derivative Assets Not Designated as Hedging Instruments:** | | | **Derivative Liabilities Not Designated as Hedging Instruments:** | | |
| **Commodity derivatives:** | | | **Commodity derivatives:** | | |
| Unrealized gains on derivative instruments — current | $ 38.2 | $ 41.2 | Unrealized losses on derivative instruments — current | $ (45.3) | $ (43.8) |
| Unrealized gains on derivative instruments — long-term | 31.2 | 6.4 | Unrealized losses on derivative instruments — long-term | (28.7) | (25.2) |
| | $ 69.4 | $ 47.6 | | $ (74.0) | $ (69.0) |
| **Interest rate derivatives:** | | | **Interest rate derivatives:** | | |
| Unrealized gains on derivative instruments — current | $ — | $ — | Unrealized losses on derivative instruments — current | $ (2.7) | $ (0.4) |
| Unrealized gains on derivative instruments — long-term | — | — | Unrealized losses on derivative instruments — long-term | — | — |
| | $ — | $ — | | $ (2.7) | $ (0.4) |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

The following table summarizes the impact on our condensed consolidated balance sheet and condensed consolidated statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting.

| | Gain (Loss) Recognized in AOCI on Derivatives — Effective Portion | | Loss Reclassified From AOCI to Earnings — Effective Portion | | Loss Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing | | Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months |
|---|---|---|---|---|---|---|---|
| | Three Months Ended March 31, | | | | | | |
| | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | |
| | (Millions) | | (Millions) | | (Millions) | | (Millions) |
| Interest rate derivatives | $ 0.2 | $ (0.9) | $(5.3) | $(5.2)(a) | $ (2.1) | $ — (a)(e) | $ (5.7) |
| Commodity derivatives | $ (0.8) | $ — | $— | $(0.1)(b) | $ — | $ — (b)(c) | $ — |
| Foreign currency derivatives (d) | $ 0.9 | $ — | $— | $— | $ — | $ — | $ — |

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) Included in sales of natural gas, propane, NGLs and condensate in our condensed consolidated statements of operations.
(c) For the three months ended March 31, 2012 and 2011, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.
(d) Relates to Discovery, our unconsolidated affiliate.
(e) For the three months ended March 31, 2012, $0.6 million of derivative losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the condensed consolidated statements of operations. The following summarizes these amounts and the location within the condensed consolidated statements of operations that such amounts are reflected:

| Commodity Derivatives: Statements of Operations Line Item | Three Months Ended March 31, 2012 | 2011 |
|---|---|---|
| | (Millions) | |
| **Third party:** | | |
| Realized | $ 16.0 | $ (6.8) |
| Unrealized | (25.0) | (32.3) |
| Losses from commodity derivative activity, net | $ (9.0) | $ (39.1) |
| **Affiliates:** | | |
| Realized | $ 1.3 | $ 1.5 |
| Unrealized | 2.4 | (2.6) |
| Gains (losses) from commodity derivative activity, net — affiliates | $ 3.7 | $ (1.1) |

| Interest Rate Derivatives: Statements of Operations Line Item | Three Months Ended March 31, 2012 | 2011 |
|---|---|---|
| | (Millions) | |
| **Third party:** | | |
| Realized | $ (2.9) | $ (1.0) |
| Unrealized | 2.8 | $ 1.6 |
| Interest (expense) gain | $ (0.1) | $ 0.6 |

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

The following tables represent, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the tables below.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | March 31, 2012 | | | |
|---|---|---|---|---|
| | Crude Oil | Natural Gas | Natural Gas Liquids | Natural Gas Basis Swaps |
| Year of Expiration | Net Long (Short) Position (Bbls) | Net Long (Short) Position (MMBtu) | Net Long (Short) Position (Bbls) | Net Long (Short) position (Mmbtu) |
| 2012 | (576,678) | (14,406,500) | (1,615,424) | 6,962,500 |
| 2013 | (938,032) | 135,000 | (655,975) | 6,472,500 |
| 2014 | (547,500) | (365,000) | (629,625) | (900,000) |
| 2015 | (365,000) | — | (155,250) | — |
| 2016 | (183,000) | — | — | — |

| | March 31, 2011 | | | |
|---|---|---|---|---|
| | Crude Oil | Natural Gas | Natural Gas Liquids | Natural Gas Basis Swaps |
| Year of Expiration | Net Long (Short) Position (Bbls) | Net Long (Short) Position (MMBtu) | Net Long (Short) Position (Bbls) | Net Long (Short) position (Mmbtu) |
| 2011 | (442,505) | (9,132,500) | (716,303) | (325,000) |
| 2012 | (1,038,762) | (7,686,000) | — | 7,150,000 |
| 2013 | (948,365) | (365,000) | — | — |
| 2014 | (547,500) | (365,000) | — | — |
| 2015 | (365,000) | — | — | — |
| 2016 | (183,000) | — | — | — |

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of March 31, 2012, we have swaps with a notional value between $25.0 million and $80.0 million, which, in aggregate, exchange up to $450.0 million of our floating rate obligation to a fixed rate obligation through June 2012, with $150.0 million extending through June 2014.

## 12. Partnership Equity and Distributions

***General*** — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash, as defined below, to unitholders of record on the applicable record date, as determined by our general partner.

In March 2012, we issued 5,148,500 common limited partner units at $47.42 per unit. We received proceeds of $234.2 million, net of offering costs.

In March 2012, we issued 1,000,417 common limited partner units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In February 2012, we issued 30,701 common limited partner units under our 2005 Long-Term Incentive Plan, or 2005 LTIP, to employees as compensation for their service.

In January 2012, we issued 727,520 common limited partner units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

On August 17, 2011, we entered into an equity distribution agreement with Citigroup Global Markets Inc., or Citi. The agreement provides for the offer and sale from time to time through Citi, our sales agent, common units having an aggregate offering amount of up to $150.0 million. During the three months ended March 31, 2012, there were no issuances pursuant to this agreement. During the year ended December 31, 2011, we issued 761,285 of our common units pursuant to this equity distribution agreement. We received proceeds of $30.2 million from the issuance of these common units, net of commissions and offering costs of $1.2 million, which were used to finance growth opportunities.

***Definition of Available Cash*** — Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; and
  - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

***General Partner Interest and Incentive Distribution Rights*** — The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 1% and limited partner interest of 1% as of March 31, 2012. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner's incentive distribution rights were not reduced as a result of our common limited partner unit issuances, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

***Distributions of Available Cash after the Subordination Period*** — Our partnership agreement, after adjustment for the general partner's relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period, which ended in February 2009, in the following manner:

- *first*, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second*, 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third*, 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter*, 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
(Unaudited)

The following table presents our cash distributions paid in 2012 and 2011:

| Payment Date | Per Unit Distribution | Total Cash Distribution (Millions) |
|---|---|---|
| February 14, 2012 | $ 0.6500 | $ 36.7 |
| November 14, 2011 | $ 0.6400 | $ 34.9 |
| August 12, 2011 | $ 0.6325 | $ 34.0 |
| May 13, 2011 | $ 0.6250 | $ 33.4 |
| February 14, 2011 | $ 0.6175 | $ 30.0 |

## 13. Equity-Based Compensation

On November 28, 2005, the board of directors of our General Partner adopted a Long-Term Incentive Plan, or the 2005 LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be issued and delivered pursuant to awards under the 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner’s tax withholding obligations, are available for delivery pursuant to other awards.

On February 15, 2012, the board of directors of our General Partner adopted a 2012 LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2012 LTIP provides for the grant of phantom units and the grant of DERs.

The 2005 and 2012 LTIPs are administered by the compensation committee of the General Partner’s board of directors. All awards are subject to cliff vesting.

Prior to February 18, 2011, substantially all equity-based awards under the 2005 LTIP were accounted for as liability awards. Effective February 18, 2011, the Modification Date, we have the intent and ability to settle certain awards within our control in units and therefore modified the accounting for these awards. We now classify them as equity awards based on their re-measured fair value. The fair value was determined based on the closing price of our common units on the Modification Date. Such modification resulted in a reclassification of $1.9 million from share-based compensation liability to additional paid-in capital on the Modification Date. Compensation expense on unvested equity awards as of the Modification Date will be recognized ratably over each remaining vesting period.

We will continue to account for other awards subject to settlement in cash as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are settled. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date.

The reclassification of the affected awards does not impact our accounting for dividend equivalent rights as these instruments will continue to be settled in cash and therefore retain their share-based compensation liability classification.

## 14. Income Taxes

We are structured as a limited partnership, which is a pass-through entity for federal income tax purposes.

## 15. Net Income or Loss per Limited Partner Unit

Basic net income per limited partner unit is computed based on the weighted average number of units outstanding during the period. Diluted net income per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding performance units, phantom units and restricted units. The dilutive effect of unit-based awards was 51,925 equivalent units and 35,998 equivalent units during the three months ended March 31, 2012 and March 31, 2011, respectively.

## 16. Commitments and Contingent Liabilities

***Prospect*** — During the fourth quarter of 2011, we received a claim for arbitration (the "Claim") filed with the American Arbitration Association by Prospect Street Energy, LLC and Prospect Street Ventures I, LLC (together, the "Claimants") against EE Group, LLC ("EE Group") and a number of other parties that previously owned, directly or indirectly, our Marysville NGL storage facility (collectively, the "Respondents"). EE Group is our indirect subsidiary which we acquired in connection with our acquisition of Marysville Hydrocarbons Holdings, LLC ("MHH") on December 30, 2010 (the "Acquisition"). The Claim involves actions taken and time periods prior to our ownership of EE Group and MHH, and includes several causes of action including claims of civil conspiracy, breach of fiduciary duty and fraud. We acquired a 90% interest in MHH from Dart Energy Corporation ("Dart"), a 5% interest in MHH from Prospect Street Energy, LLC and a 100% interest in EE Group, which owned the remaining 5% interest in MHH. The Claim seeks, from the Respondents collectively, alleged actual, punitive and treble damages and disgorgement of profits, as well as fees and costs. The purchase agreements for the Acquisition contain indemnification and other provisions that may provide some protection to us for any breach of the representations, warranties and covenants made by the sellers in the Acquisition. At this point, we cannot predict whether we will have any liability for the Claim. This proceeding is subject to the uncertainties inherent in any litigation, and the ultimate outcome of this matter may not be known for an extended period of time. We intend to vigorously defend this matter.

***Other*** — We are not a party to any other significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated results of operations, financial position, or cash flow.

***Insurance*** — We renewed our insurance policies in May, June and July 2011 for the 2011-2012 insurance year. We contract with third party and affiliate insurers for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) general liability insurance; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of real and personal property and includes business interruption/extra expense. These renewals have not resulted in any material change to the premiums we are contracted to pay in the 2011-2012 insurance year compared with the 2010-2011 insurance year. We are jointly insured with DCP Midstream, LLC for directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

Our insurance on Discovery for the 2011-2012 insurance year includes general and excess liability, onshore property damage, including named windstorm and business interruption, and offshore non-wind property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past few years as a result of higher industry-wide damage claims. Additionally, the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, higher deductibles and lower coverage limits. As such, Discovery has elected to not purchase offshore named windstorm property and business interruption insurance coverage for the 2011-2012 insurance year.

***Environmental*** — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

During the first quarter of 2011, we discovered excess emissions at our East Texas gas plant. We met with the Texas Commission on Environmental Quality, or TCEQ, in April 2011 to discuss this matter and included these issues in Title V reports we submitted to the State. In August 2011, the TCEQ conducted a standard inspection at the East Texas gas plant to evaluate compliance with applicable air quality requirements. On August 31, 2011, the TCEQ issued us a Notice of Violation and a Notice of Enforcement citing a number of alleged violations of terms and requirements of the facility air permit. We responded to the Notice of Violation on September 28, 2011, including the implemented measures to ensure the facility is in compliance with the relevant air permit terms and conditions. We responded to the Notice of Enforcement on October 14, 2011, including a description of the measures that have been implemented, and will be implemented at the facility to ensure compliance with the relevant air permit terms and conditions. The TCEQ assessed a penalty of $0.6 million to resolve this matter, a portion which was paid during the first quarter of 2012. We were only responsible for 50.1% of this penalty and DCP Midstream, LLC was responsible for the remainder of the penalty under the terms of our acquisition of a 49.9% interest in East Texas from DCP Midstream, LLC on January 3, 2012.

***Indemnification*** — DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors.

## 17. Business Segments

Our operations are located in the United States and are organized into three reporting segments: (1) Natural Gas Services; (2) NGL Logistics; and (3) Wholesale Propane Logistics.

***Natural Gas Services*** — Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, transporting and storing natural gas. The segment consists of our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our Michigan system, our Southeast Texas system, our East Texas system, our 75% interest in the Colorado system, and our 40% limited liability company interest in Discovery.

***NGL Logistics*** — Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, the NGL storage facility in Michigan and the DJ Basin NGL Fractionators in Colorado.

***Wholesale Propane Logistics*** — Our Wholesale Propane Logistics segment provides services that include the receipt of propane by pipeline, rail or ship to our terminals that deliver the product to retail distributors. The segment consists of six owned rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment.

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**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

The following tables set forth our segment information:

**Three Months Ended March 31, 2012**

| | Natural Gas Services (e) | NGL Logistics | Wholesale Propane Logistics | Other | Eliminations (f) | Total |
|---|---|---|---|---|---|---|
| | | | (Millions) | | | |
| Total operating revenue | $ 305.7 | $ 15.9 | $ 204.0 | $ — | $ — | $ 525.6 |
| Total purchases | (248.4) | — | (182.8) | — | — | (431.2) |
| Gross margin (a) | $ 57.3 | $ 15.9 | $ 21.2 | $ — | $ — | $ 94.4 |
| Operating and maintenance expense | (18.3) | (4.2) | (3.8) | — | — | (26.3) |
| Depreciation and amortization expense | (22.3) | (2.2) | (0.7) | — | — | (25.2) |
| General and administrative expense | — | — | — | (11.9) | — | (11.9) |
| Other income | — | 0.1 | — | — | — | 0.1 |
| Earnings from unconsolidated affiliates | 5.7 | — | — | — | — | 5.7 |
| Interest expense | — | — | — | (12.6) | — | (12.6) |
| Income tax expense (b) | — | — | — | (0.2) | — | (0.2) |
| Net income (loss) | 22.4 | 9.6 | 16.7 | (24.7) | — | 24.0 |
| Net income attributable to noncontrolling interests | (0.7) | — | — | — | — | (0.7) |
| Net income (loss) attributable to partners | $ 21.7 | $ 9.6 | $ 16.7 | $ (24.7) | $ — | $ 23.3 |
| Non-cash derivative mark-to-market (c) | $ (23.0) | $ — | $ 0.4 | $ (1.2) | $ — | $ (23.8) |
| Capital expenditures | $ 51.3 | $ 1.5 | $ 0.6 | $ — | $ — | $ 53.4 |
| Acquisition expenditures | $ 311.4 | $ — | $ — | $ — | $ — | $ 311.4 |

**Three Months Ended March 31, 2011**

| | Natural Gas Services (e) | NGL Logistics | Wholesale Propane Logistics | Other | Eliminations (f) | Total |
|---|---|---|---|---|---|---|
| | | | (Millions) | | | |
| Total operating revenue | $ 373.3 | $ 15.0 | $ 247.8 | $ — | $ (2.2) | $ 633.9 |
| Total purchases | (333.6) | (4.7) | (226.0) | — | 2.2 | (562.1) |
| Gross margin (a) | $ 39.7 | $ 10.3 | $ 21.8 | $ — | $ — | $ 71.8 |
| Operating and maintenance expense | (21.0) | (4.0) | (3.6) | — | — | (28.6) |
| Depreciation and amortization expense | (21.9) | (1.7) | (0.7) | — | — | (24.3) |
| General and administrative expense | — | — | — | (11.7) | — | (11.7) |
| Other income | — | 0.1 | — | — | — | 0.1 |
| Earnings from unconsolidated affiliates | 4.5 | — | — | — | — | 4.5 |
| Interest expense | — | — | — | (8.0) | — | (8.0) |
| Income tax expense (b) | — | — | — | (0.3) | — | (0.3) |
| Net income (loss) | 1.3 | 4.7 | 17.5 | (20.0) | — | 3.5 |
| Net income attributable to noncontrolling interests | (3.5) | — | — | — | — | (3.5) |
| Net (loss) income attributable to partners | $ (2.2) | $ 4.7 | $ 17.5 | $ (20.0) | $ — | $ — |
| Non-cash derivative mark-to-market (c) | $ (34.6) | $ — | $ (0.3) | $ (0.2) | $ — | $ (35.1) |
| Capital expenditures | $ 28.2 | $ 4.3 | $ 0.6 | $ — | $ — | $ 33.1 |
| Acquisition expenditures | $ 121.8 | $ 29.6 | $ — | $ — | $ — | $ 151.4 |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | March 31, 2012 | December 31, 2011 |
|---|---|---|
| | (Millions) | |
| Segment long-term assets: | | |
| Natural Gas Services (e) | $1,620.5 | $ 1,555.4 |
| NGL Logistics | 260.8 | 250.1 |
| Wholesale Propane Logistics | 103.9 | 104.2 |
| Other (d) | 12.3 | 14.0 |
| Total long-term assets | 1,997.5 | 1,923.7 |
| Current assets | 291.4 | 353.7 |
| Total assets | $2,288.9 | $ 2,277.4 |

(a) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane, NGLs and condensate. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) For the three months ended March 31, 2011, income tax expense relates primarily to the Texas margin tax and the Michigan business tax. The Michigan business tax was repealed in 2012; accordingly, income tax expense for the three months ended March 31, 2012 relates primarily to the Texas margin tax.

(c) Non-cash derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

(d) Other long-term assets not allocable to segments consist of unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

(e) The segment information for the three months ended March 31, 2012 and 2011, and as of December 31, 2011, include the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

(f) Represents intersegment revenues consisting of sales of NGLs by Marysville in our NGL Logistics business to our Wholesale Propane business.

## 18. Supplemental Cash Flow Information

| | Three Months Ended March 31, 2012 | 2011 |
|---|---|---|
| | (Millions) | |
| Cash paid for interest: | | |
| Cash paid for interest, net of amounts capitalized | $ 1.5 | $ 1.2 |
| Non-cash investing and financing activities: | | |
| Property, plant and equipment acquired with accounts payable | $23.7 | $11.7 |
| Other non-cash additions of property, plant and equipment | $ 5.8 | $ 0.1 |
| Accounts payable related to equity issuance costs | $ 0.2 | $ 0.1 |
| Non-cash change in parent advances | $ — | $ 4.3 |
| Non-cash distributions to DCP Midstream, LLC | $ — | $ 2.6 |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

### 19. Supplementary Information — Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a 100% owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP's results on a consolidated basis. In conjunction with the universal shelf registration statement on Form S-3 filed with the SEC on May 26, 2010, the parent guarantor has agreed to fully and unconditionally guarantee securities of the subsidiary issuer. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

| | Condensed Consolidating Balance Sheets March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ — | $ 1.3 | $ 4.8 | $ — | $ 6.1 |
| Accounts receivable | — | — | 176.8 | — | 176.8 |
| Inventories | — | — | 69.0 | — | 69.0 |
| Other | — | — | 39.5 | — | 39.5 |
| Total current assets | — | 1.3 | 290.1 | — | 291.4 |
| Property, plant and equipment, net | — | — | 1,546.1 | — | 1,546.1 |
| Goodwill and intangible assets, net | — | — | 297.0 | — | 297.0 |
| Advances receivable — consolidated subsidiaries | 649.1 | 703.3 | — | (1,352.4) | — |
| Investments in consolidated subsidiaries | 376.0 | 546.9 | — | (922.9) | — |
| Investments in unconsolidated affiliates | — | — | 108.5 | — | 108.5 |
| Other long-term assets | — | 8.2 | 37.7 | — | 45.9 |
| Total assets | $1,025.1 | $1,259.7 | $ 2,279.4 | $ (2,275.3) | $ 2,288.9 |
| **LIABILITIES AND EQUITY** | | | | | |
| Accounts payable and other current liabilities | $ 0.2 | $ 14.2 | $ 290.1 | $ — | $ 304.5 |
| Advances payable — consolidated subsidiaries | — | — | 1,352.4 | (1,352.4) | — |
| Long-term debt | — | 865.2 | — | — | 865.2 |
| Other long-term liabilities | — | 4.3 | 54.4 | — | 58.7 |
| Total liabilities | 0.2 | 883.7 | 1,696.9 | (1,352.4) | 1,228.4 |
| Commitments and contingent liabilities | | | | | |
| Equity: | | | | | |
| Partners' equity | | | | | |
| Net equity | 1,024.9 | 389.9 | 552.2 | (922.9) | 1,044.1 |
| Accumulated other comprehensive loss | — | (13.9) | (5.3) | — | (19.2) |
| Total partners' equity | 1,024.9 | 376.0 | 546.9 | (922.9) | 1,024.9 |
| Noncontrolling interests | — | — | 35.6 | — | 35.6 |
| Total equity | 1,024.9 | 376.0 | 582.5 | (922.9) | 1,060.5 |
| Total liabilities and equity | $1,025.1 | $1,259.7 | $ 2,279.4 | $ (2,275.3) | $ 2,288.9 |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Balance Sheets December 31, 2011 (a) | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ — | $ 3.6 | $ 6.4 | $ (2.4) | $ 7.6 |
| Accounts receivable | — | — | 214.8 | — | 214.8 |
| Inventories | — | — | 87.9 | — | 87.9 |
| Other | — | — | 43.4 | — | 43.4 |
| Total current assets | — | 3.6 | 352.5 | (2.4) | 353.7 |
| Property, plant and equipment, net | — | — | 1,499.4 | — | 1,499.4 |
| Goodwill and intangible assets, net | — | — | 299.1 | — | 299.1 |
| Advances receivable — consolidated subsidiaries | 370.7 | 597.2 | — | (967.9) | — |
| Investments in consolidated subsidiaries | 515.2 | 679.3 | — | (1,194.5) | — |
| Investments in unconsolidated affiliates | — | — | 107.1 | — | 107.1 |
| Other long-term assets | — | 5.6 | 12.5 | — | 18.1 |
| Total assets | $ 885.9 | $1,285.7 | $ 2,270.6 | $ (2,164.8) | $ 2,277.4 |
| **LIABILITIES AND EQUITY** | | | | | |
| Accounts payable and other current liabilities | $ — | $ 18.7 | $ 364.2 | $ (2.4) | $ 380.5 |
| Advances payable — consolidated subsidiaries | — | — | 967.9 | (967.9) | — |
| Long-term debt | — | 746.8 | — | — | 746.8 |
| Other long-term liabilities | — | 5.0 | 46.8 | — | 51.8 |
| Total liabilities | — | 770.5 | 1,378.9 | (970.3) | 1,179.1 |
| Commitments and contingent liabilities | | | | | |
| Equity: | | | | | |
| Partners' equity | | | | | |
| Predecessor equity | — | — | 257.4 | — | 257.4 |
| Net equity | 885.9 | 534.6 | 423.7 | (1,194.5) | 649.7 |
| Accumulated other comprehensive loss | — | (19.4) | (1.8) | — | (21.2) |
| Total partners' equity | 885.9 | 515.2 | 679.3 | (1,194.5) | 885.9 |
| Noncontrolling interests | — | — | 212.4 | — | 212.4 |
| Total equity | 885.9 | 515.2 | 891.7 | (1,194.5) | 1,098.3 |
| Total liabilities and equity | $ 885.9 | $1,285.7 | $ 2,270.6 | $ (2,164.8) | $ 2,277.4 |

(a) The financial information as of December 31, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Statements of Operations Three Months Ended March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| Operating revenues: | | | | | |
| Sales of natural gas, propane, NGLs and condensate | $ — | $ — | $ 487.1 | $ — | $ 487.1 |
| Transportation, processing and other | — | — | 43.8 | — | 43.8 |
| Losses from commodity derivative activity, net | — | — | (5.3) | — | (5.3) |
| Total operating revenues | — | — | 525.6 | — | 525.6 |
| Operating costs and expenses: | | | | | |
| Purchases of natural gas, propane and NGLs | — | — | 431.2 | — | 431.2 |
| Operating and maintenance expense | — | — | 26.3 | — | 26.3 |
| Depreciation and amortization expense | — | — | 25.2 | — | 25.2 |
| General and administrative expense | — | — | 11.9 | — | 11.9 |
| Other income | — | — | (0.1) | — | (0.1) |
| Total operating costs and expenses | — | — | 494.5 | — | 494.5 |
| Operating income | — | — | 31.1 | — | 31.1 |
| Interest expense, net | — | (12.4) | (0.2) | — | (12.6) |
| Income from consolidated subsidiaries | 23.3 | 35.7 | — | (59.0) | — |
| Earnings from unconsolidated affiliates | — | — | 5.7 | — | 5.7 |
| Income before income taxes | 23.3 | 23.3 | 36.6 | (59.0) | 24.2 |
| Income tax expense | — | — | (0.2) | — | (0.2) |
| Net income | 23.3 | 23.3 | 36.4 | (59.0) | 24.0 |
| Net income attributable to noncontrolling interests | — | — | (0.7) | — | (0.7) |
| Net income attributable to partners | $ 23.3 | $ 23.3 | $ 35.7 | $ (59.0) | $ 23.3 |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Statements of Comprehensive Income Three Months Ended March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| Net income | $ 23.3 | $ 23.3 | $ 36.4 | $ (59.0) | $ 24.0 |
| Other comprehensive income: | | | | | |
| Reclassification of cash flow hedges into earnings | — | 5.3 | — | — | 5.3 |
| Net unrealized gains on cash flow hedges | — | 0.2 | 0.1 | — | 0.3 |
| Total other comprehensive income | — | 5.5 | 0.1 | — | 5.6 |
| Total comprehensive income | 23.3 | 28.8 | 36.5 | (59.0) | 29.6 |
| Total comprehensive income attributable to noncontrolling interests | — | — | (0.7) | — | (0.7) |
| Total comprehensive income attributable to partners | $ 23.3 | $ 28.8 | $ 35.8 | $ (59.0) | $ 28.9 |

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**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Statements of Operations Three Months Ended March 31, 2011 (a) | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| Operating revenues: | | | | | |
| Sales of natural gas, propane, NGLs and condensate | $ — | $ — | $ 635.1 | $ — | $ 635.1 |
| Transportation, processing and other | — | — | 39.0 | — | 39.0 |
| Losses from commodity derivative activity, net | — | — | (40.2) | — | (40.2) |
| Total operating revenues | — | — | 633.9 | — | 633.9 |
| Operating costs and expenses: | | | | | |
| Purchases of natural gas, propane and NGLs | — | — | 562.1 | — | 562.1 |
| Operating and maintenance expense | — | — | 28.6 | — | 28.6 |
| Depreciation and amortization expense | — | — | 24.3 | — | 24.3 |
| General and administrative expense | — | — | 11.7 | — | 11.7 |
| Other income | — | — | (0.1) | — | (0.1) |
| Total operating costs and expenses | — | — | 626.6 | — | 626.6 |
| Operating | — | — | 7.3 | — | 7.3 |
| Interest expense, net | — | (8.0) | — | — | (8.0) |
| Income from consolidated subsidiaries | — | — | 4.5 | — | 4.5 |
| Earnings from unconsolidated affiliates | — | 8.0 | — | (8.0) | — |
| Income before income taxes | — | — | 11.8 | (8.0) | 3.8 |
| Income tax expense | — | — | (0.3) | — | (0.3) |
| Net income | — | — | 11.5 | (8.0) | 3.5 |
| Net income attributable to noncontrolling interests | — | — | (3.5) | — | (3.5) |
| Net income attributable to partners | $ — | $ — | $ 8.0 | $ (8.0) | $ — |

(a) The financial information for the three months ended March 31, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Statements of Comprehensive Income Three Months Ended March 31, 2011 (a) | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | (Millions) | | | | |
| Net income | $ — | $ — | $ 11.5 | $ (8.0) | $ 3.5 |
| Other comprehensive income: | | | | | |
| Reclassification of cash flow hedges into earnings | — | 5.2 | 0.1 | — | 5.3 |
| Net unrealized (losses) on cash flow hedges | — | (0.9) | — | — | (0.9) |
| Total other comprehensive income | — | 4.3 | 0.1 | — | 4.4 |
| Total comprehensive income | — | 4.3 | 11.6 | (8.0) | 7.9 |
| Total comprehensive income attributable to noncontrolling interests | — | — | (3.5) | — | (3.5) |
| Total comprehensive income attributable to partners | $ — | $ 4.3 | $ 8.1 | $ (8.0) | $ 4.4 |

(a) The financial information for the three months ended March 31, 2011 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Statements of Cash Flows Three Months Ended March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| OPERATING ACTIVITIES | | | | | |
| Net cash (used in) provided by operating activities | $ (197.5) | $ (119.0) | $ 374.1 | $ 3.4 | $ 61.0 |
| INVESTING ACTIVITIES: | | | | | |
| Capital expenditures | — | — | (53.4) | — | (53.4) |
| Acquisitions, net of cash acquired | — | — | (311.4) | — | (311.4) |
| Investments in unconsolidated affiliates | — | — | (1.5) | — | (1.5) |
| Return of investment in unconsolidated affiliates | — | — | 1.0 | — | 1.0 |
| Proceeds from sale of assets | — | — | 0.1 | — | 0.1 |
| Net cash used in investing activities | — | — | (365.2) | — | (365.2) |
| FINANCING ACTIVITIES: | | | | | |
| Proceeds from debt | — | 722.4 | — | — | 722.4 |
| Payments of debt | — | (604.0) | — | — | (604.0) |
| Payment of deferred financing costs | — | (2.7) | — | — | (2.7) |
| Proceeds from issuance of common units, net of offering costs | 234.2 | — | — | — | 234.2 |
| Distributions to unitholders and general partner | (36.7) | — | — | — | (36.7) |
| Distributions to noncontrolling interests | — | — | (1.7) | — | (1.7) |
| Contributions from DCP Midstream, LLC | — | — | 2.7 | — | 2.7 |
| Net change in advances to predecessor from DCP Midstream, LLC | — | — | (11.5) | — | (11.5) |
| Net change in short-term borrowings | — | 1.0 | — | (1.0) | — |
| Net cash provided by (used in) financing activities | 197.5 | 116.7 | (10.5) | (1.0) | 302.7 |
| Net change in cash and cash equivalents | — | (2.3) | (1.6) | 2.4 | (1.5) |
| Cash and cash equivalents, beginning of period | — | 3.6 | 6.4 | (2.4) | 7.6 |
| Cash and cash equivalents, end of period | $ — | $ 1.3 | $ 4.8 | $ — | $ 6.1 |

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

| | Condensed Consolidating Statements of Cash Flows Three Months Ended March 31, 2011 (a) | | | | |
|---|---|---|---|---|---|
| | Parent Guarantor | Subsidiary Issuer | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| | | | (Millions) | | |
| OPERATING ACTIVITIES | | | | | |
| Net cash (used in) provided by operating activities | $ (109.6) | $ (27.9) | $ 230.0 | $ 0.2 | $ 92.7 |
| INVESTING ACTIVITIES: | | | | | |
| Capital expenditures | — | — | (33.1) | — | (33.1) |
| Acquisitions, net of cash acquired | — | — | (151.4) | — | (151.4) |
| Investments in unconsolidated affiliates | — | — | (0.1) | — | (0.1) |
| Proceeds from sale of assets | — | — | 0.2 | — | 0.2 |
| Net cash used in investing activities | — | — | (184.4) | — | (184.4) |
| FINANCING ACTIVITIES: | | | | | |
| Proceeds from debt | — | 547.0 | — | — | 547.0 |
| Payments of debt | — | (519.0) | — | — | (519.0) |
| Payments of deferred financing cost | — | (0.1) | — | — | (0.1) |
| Proceeds from issuance of common units, net of offering cost | 139.7 | — | — | — | 139.7 |
| Excess purchase price over acquired assets | — | — | (35.7) | — | (35.7) |
| Distributions to unitholders and general partner | (30.1) | — | — | — | (30.1) |
| Distributions to noncontrolling interests | — | — | (5.4) | — | (5.4) |
| Contributions from DCP Midstream, LLC | — | — | 2.9 | — | 2.9 |
| Net change in advances to predecessor from DCP Midstream LLC | — | — | (7.2) | — | (7.2) |
| Net cash provided by (used in) financing activities | 109.6 | 27.9 | (45.4) | — | 92.1 |
| Net change in cash and cash equivalents | — | — | 0.2 | 0.2 | 0.4 |
| Cash and cash equivalents, beginning of period | — | 1.5 | 6.7 | (1.5) | 6.7 |
| Cash and cash equivalents, end of period | $ — | $ 1.5 | $ 6.9 | $ (1.3) | $ 7.1 |

(a) The financial information during the three months ended March 31, 2011 includes the results of Southeast Texas, a transfers of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

**20. Subsequent Events**

On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline joint venture from the operator, Enterprise Products Partners, L.P., or Enterprise, representing an approximate investment of $85.0 million in the joint venture. At closing, we paid $10.9 million for our 10% ownership interest, representing our proportionate share of the investment to date, in the Texas Express Pipeline joint venture and will be responsible for spending an approximate $75.0 million for our share of the remaining construction costs of the pipeline. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express Pipeline mainline will extend approximately 580 miles to Enterprise’s natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and will provide access to other third-party facilities in the area. The pipeline entered into long-term, fee-based, ship-or-pay transportation agreements and is expected to be completed by the second quarter of 2013. DCP Midstream, LLC has provided shipping commitments of 20 MBbls/d to the pipeline, increasing total long term shipper commitments to 252 MBbls/d.

**DCP MIDSTREAM PARTNERS, LP**
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**
**(Unaudited)**

On April 27, 2012, the board of directors of the General Partner declared a quarterly distribution of $0.66 per unit, payable on May 15, 2012 to unitholders of record on May 8, 2012.

In conjunction with our acquisition of Marysville on December 30, 2010 for an aggregate purchase price of $100.8 million, $21.2 million of the purchase price was deposited in escrow accounts to satisfy certain tax liabilities and provide for breaches of representations and warranties of the sellers. During 2011, $1.7 million was released from the escrow account for certain tax liabilities. In May 2012, an additional $8.9 million was released from escrow to satisfy additional tax liabilities. $10.6 million remains in the escrow accounts.

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

*The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our 2011 Form 10-K.*

## Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Our operations are organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics.

Crude oil and natural gas liquids prices continue to be volatile, but have generally remained at favorable levels, while natural gas prices have declined substantially, and are currently below levels seen in several years due to increasing supplies and a near record warm winter. Although we have not experienced a significant impact to our natural gas throughput volumes as a result of decreased natural gas prices, if natural gas prices remain depressed for a sustained period, our natural gas throughput volumes may be impacted, particularly if producers were to shut in gas. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains robust in areas with liquids rich gas. Drilling remains depressed in certain areas with dry gas where low natural gas prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic natural gas production.

The global economic outlook, particularly the European debt crisis, has become a cause for concern for U.S. financial markets as businesses and investors alike struggle to determine the impact these troubled nations will have domestically. A slowdown in economic growth or a potential liquidity crunch may lead to further declines in commodity prices. This uncertainty may contribute to continuing volatility in financial and commodity markets.

Despite a somewhat tepid economy, increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low historical cost have enabled us to continue executing our multi-faceted growth strategy, with an emphasis on co-investment with DCP Midstream, LLC. Co-investment capital commitments announced to date are $790.0 million.

On January 3, 2012, we closed on the previously announced acquisition of the remaining 49.9% interest in East Texas from DCP Midstream, LLC for $165.0 million. On March 30, 2012, we closed on the previously announced acquisition of the remaining 66.67% interest in the Southeast Texas joint venture for $240.0 million.

On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline joint venture from the operator, Enterprise Products Partners, L.P., representing an investment of approximately $85.0 million. Originating near Skellytown, Texas, the 20-inch diameter NGL pipeline will extend approximately 580 miles to Enterprise's fractionation and storage complex at Mont Belvieu, Texas, and other third-party facilities in the Gulf Coast, providing much-needed takeaway capacity from the Rockies, Permian Basin, and Mid-Continent to the Gulf Coast. In conjunction with the construction, Texas Express entered into long-term, fee-based, ship-or-pay transportation agreements. This investment is also integral to DCP Midstream's assets and strategic positioning in the NGL infrastructure business. DCP Midstream is providing shipping commitments of 20 MBbls/d to the pipeline, increasing total long term shipper commitments to 252 MBbls/d. The pipeline is expected to be completed by the second quarter of 2013.

Our construction of the Eagle 200 MMcf/d natural gas processing plant is progressing on plan and is expected to be online by the fourth quarter of 2012. Our expansion plan for the Discovery natural gas gathering pipeline system is also progressing on plan and is expected to be completed in mid-2014. Once completed, both projects are expected to enhance our portfolio through additional fee-based margins.

Our capital markets execution has positioned us well in terms of both liquidity and cost of capital to execute our growth plans, including co-investment opportunities with DCP Midstream, LLC. In March, we raised $234.4 million in capital through a public equity offering and $345.8 million through a public debt offering of 4.95% 10-year Senior Notes, which were used to finance our growth opportunities and repay borrowings on our credit facility.

Financial results for the first quarter were in line with our previously provided 2012 forecast. We raised our distributions for the quarter, resulting in a 5.6% increase in our quarterly distribution rate over the rate declared in the first quarter of 2011. The distributions reflect our business results as well as our recent execution on growth opportunities.

**General Trends and Outlook**

In 2012, our strategic objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio, our significant fee-based business representing approximately 60% of our estimated margins, plus our highly hedged commodity position, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $15.0 million and $20.0 million, and expenditures for expansion capital of between $300.0 million and $360.0 million, for the year ending December 31, 2012. Expansion capital expenditures include construction of the Texas Express Pipeline and Discovery's Keathley Canyon, which are shown as investments in unconsolidated affiliates, construction of the Eagle Plant, expansion and upgrades to our East Texas complex, and acquisition integration projects. The board of directors may, in its discretion, approve additional growth capital during the year.

In 2012, we expect to continue to pursue a multi-faceted growth strategy, which includes maximizing opportunities provided by our partnership with DCP Midstream, LLC, pursuing strategic and accretive third party acquisitions and capitalizing on organic expansion opportunities in order to grow our distributable cash flows. Given the significant level of growth opportunities currently in DCP Midstream, LLC's footprint, we would expect substantially more emphasis on our co-investment objective over the next few years.

For an in-depth discussion of factors that may significantly affect our results, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors That May Significantly Affect Our Results" in our 2011 Form 10-K.

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for all periods presented. We refer to our 100% interest in Southeast Texas, prior to our acquisition from DCP Midstream, LLC in March 2012, as our "predecessor." We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets is recognized as a reduction to partners' equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

**Recent Events**

In March 2012, we issued 5,148,500 common limited partner units at $47.42 per unit. We received proceeds of $234.2 million, net of offering costs.

In March, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, which are net of underwriters' fees, related expenses and unamortized, which we used to fund the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Facility.

On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. $192.0 million of the aggregate purchase price was financed with a portion of the net proceeds from our 4.95% 10-year Senior Notes offering. The remaining $48.0 million consideration was financed by the issuance at closing of an aggregate of 1,000,417 of our common units. DCP Midstream, LLC also provided fixed price NGL commodity derivatives, valued at $39.5 million, for the three year period subsequent to closing the newly acquired interest. Certain of the NGL commodity derivatives were valued at $24.6 million and represent consideration for the termination of a fee-based storage arrangement we had with DCP Midstream, LLC in conjunction with our initial 33.33% interest in Southeast Texas; the remaining portion of the commodity derivatives, valued at $14.9 million, mitigate a portion of our currently anticipated commodity price risk associated with the gathering and processing portion of the 66.67% interest in Southeast Texas acquired on March 30, 2012.

On April 12, 2012, we acquired a 10% ownership interest in the Texas Express Pipeline. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express Pipeline mainline will extend approximately 580 miles to Enterprise's natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and will provide access to other third-party facilities in the area. The pipeline entered into long-term, fee-based, ship-or-pay transportation agreements and is expected to be completed by the second quarter of 2013. DCP Midstream, LLC has provided shipping commitments of 20 MBbls/d to the pipeline, increasing total long term shipper commitments to 252 MBbls/d.

On April 27, 2012, the board of directors of the General Partner declared a quarterly distribution of $0.66 per unit, payable on May 15, 2012 to unitholders of record on May 8, 2012.

In conjunction with our acquisition of Marysville on December 30, 2010 for an aggregate purchase price of $100.8 million, $21.2 million of the purchase price was deposited in escrow accounts to satisfy certain tax liabilities and provide for breaches of representations and warranties of the sellers. During 2011, $1.7 million was released from the escrow account for certain tax liabilities. In May 2012, an additional $8.9 million was released from escrow to satisfy additional tax liabilities. $10.6 million remains in the escrow accounts.

**Reconciliation of Non-GAAP Measures**

***Gross Margin, Segment Gross Margin and Adjusted Segment Gross Margin*** — We view our gross margin as an important performance measure of the core profitability of our operations. We review our gross margin monthly for consistency and trend analysis.

We define gross margin as total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. We define adjusted segment gross margin as segment gross margin plus non-cash commodity derivative losses, less non-cash commodity derivative gains for that segment. Gross margin, segment gross margin and adjusted segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin, segment gross margin and adjusted segment gross margin should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States of America, or GAAP.

***Adjusted EBITDA*** — We define adjusted EBITDA as net income or loss attributable to partners less interest income, noncontrolling interest in depreciation and income tax expense and non-cash commodity derivative gains, plus interest expense, income tax expense, depreciation and amortization expense and non-cash commodity derivative losses. Our adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate this measure in the same manner.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

***Adjusted Segment EBITDA*** — We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners less non-cash commodity derivative gains for that segment, plus depreciation and amortization expense and non-cash commodity derivative losses for that segment, adjusted for any noncontrolling interest on depreciation and amortization expense for that segment. Our adjusted segment EBITDA may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

Adjusted segment EBITDA should not be considered in isolation or as an alternative to our financial measures presented in accordance with GAAP, including net income or loss attributable to Partners, or any other measure of performance presented in accordance with GAAP.

Adjusted EBITDA is used as a supplemental liquidity and performance measure and adjusted segment EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure; and
- viability and performance of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities;
- in the case of Adjusted EBITDA, the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures.

The accompanying schedules provide reconciliations of adjusted segment EBITDA to its most directly comparable GAAP financial measure.

***Distributable Cash Flow*** — We define Distributable Cash Flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, net income attributable to noncontrolling interest net of depreciation and income tax, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see "— Liquidity and Capital Resources" for further definition of maintenance capital expenditures). Maintenance capital expenditures are capital expenditures made where we add on to or improve capital assets owned, or acquire or construct new capital assets, if such expenditures are made to maintain, including over the long-term, our operating or earnings capacity. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing Distributable Cash Flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices and interest rates. Distributable Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner. Our Distributable Cash Flow may not be comparable to a similarly titled measure of another company because other entities may not calculate Distributable Cash Flow in the same manner.

Our gross margin, segment gross margin, adjusted segment gross margin and adjusted segment EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures:

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| **Reconciliation of Non-GAAP Measures** | | |
| **Reconciliation of net income attributable to partners to gross margin:** | | |
| Net income attributable to partners | $ 23.3 | $ — |
| Interest expense | 12.6 | 8.0 |
| Income tax expense | 0.2 | 0.3 |
| Operating and maintenance expense | 26.3 | 28.6 |
| Depreciation and amortization expense | 25.2 | 24.3 |
| General and administrative expense | 11.9 | 11.7 |
| Other income | (0.1) | (0.1) |
| Earnings from unconsolidated affiliates | (5.7) | (4.5) |
| Net income attributable to noncontrolling interests | 0.7 | 3.5 |
| Gross margin | $ 94.4 | $ 71.8 |
| Non-cash commodity derivative mark-to-market (a) | $ (22.6) | $ (34.9) |
| **Reconciliation of segment net income attributable to partners to segment gross margin:** | | |
| ***Natural Gas Services segment:*** | | |
| Segment net income (loss) attributable to partners | $ 21.7 | $ (2.2) |
| Operating and maintenance expense | 18.3 | 21.0 |
| Depreciation and amortization expense | 22.3 | 21.9 |
| Earnings from unconsolidated affiliates | (5.7) | (4.5) |
| Net income attributable to noncontrolling interests | 0.7 | 3.5 |
| Segment gross margin | $ 57.3 | $ 39.7 |
| Non-cash commodity derivative mark-to-market (a) | $ (23.0) | $ (34.6) |
| ***NGL Logistics segment:*** | | |
| Segment net income attributable to partners | $ 9.6 | $ 4.7 |
| Operating and maintenance expense | 4.2 | 4.0 |
| Depreciation and amortization expense | 2.2 | 1.7 |
| Other income | (0.1) | (0.1) |
| Segment gross margin | $ 15.9 | $ 10.3 |
| ***Wholesale Propane Logistics segment:*** | | |
| Segment net income attributable to partners | $ 16.7 | $ 17.5 |
| Operating and maintenance expense | 3.8 | 3.6 |
| Depreciation and amortization expense | 0.7 | 0.7 |
| Segment gross margin | $ 21.2 | $ 21.8 |
| Non-cash commodity derivative mark-to-market (a) | $ 0.4 | $ (0.3) |

(a) Non-cash commodity derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

| | Three Months Ended March 31, 2012 | Three Months Ended March 31, 2011 |
|---|---|---|
| | (Millions) | |
| **Reconciliation of net income attributable to partners to adjusted segment EBITDA:** | | |
| ***Natural Gas Services segment:*** | | |
| Segment net income (loss) attributable to partners | $ 21.7 | $ (2.2) |
| Non-cash commodity derivative mark-to-market | 23.0 | 34.6 |
| Depreciation and amortization expense | 22.3 | 21.9 |
| Noncontrolling interest on depreciation and income tax | (0.4) | (3.6) |
| Adjusted Segment EBITDA | $ 66.6 | $ 50.7 |
| ***NGL Logistics segment:*** | | |
| Segment net income attributable to partners | $ 9.6 | $ 4.7 |
| Depreciation and amortization expense | 2.2 | 1.7 |
| Adjusted Segment EBITDA | $ 11.8 | $ 6.4 |
| ***Wholesale Propane Logistics segment:*** | | |
| Segment net income attributable to partners | $ 16.7 | $ 17.5 |
| Non-cash commodity derivative mark-to-market | (0.4) | 0.3 |
| Depreciation and amortization expense | 0.7 | 0.7 |
| Adjusted Segment EBITDA | $ 17.0 | $ 18.5 |

**Critical Accounting Policies and Estimates**

Our critical accounting policies and estimates are described in Item 7 in our 2011 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three months ended March 31, 2012 are the same as those described in our 2011 Form 10-K, as updated by recent accounting pronouncements that we have adopted in Note 2 of the Notes to Condensed Consolidated Financial Statements in Item 1. "Financial Statements".

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## Results of Operations

### *Consolidated Overview*

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2012 and 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

| | Three Months Ended March 31, | | Variance Three Months 2012 vs. 2011 | |
|---|---|---|---|---|
| | 2012 (a)(b)(c) | 2011 (a)(c)(d) | Increase (Decrease) | Percent |
| | (Millions, except as indicated) | | | |
| Operating revenues (g): | | | | |
| Natural Gas Services | $ 305.7 | $ 373.3 | $ (67.6) | (18)% |
| NGL Logistics | 15.9 | 15.0 | 0.9 | 6% |
| Wholesale Propane Logistics | 204.0 | 247.8 | (43.8) | (18)% |
| Intra-segment Eliminations | — | (2.2) | 2.2 | 100% |
| Total operating revenues | 525.6 | 633.9 | (108.3) | (17)% |
| Gross margin (e): | | | | |
| Natural Gas Services | 57.3 | 39.7 | 17.6 | 44% |
| NGL Logistics | 15.9 | 10.3 | 5.6 | 54% |
| Wholesale Propane Logistics | 21.2 | 21.8 | (0.6) | (3)% |
| Total gross margin | 94.4 | 71.8 | 22.6 | 31% |
| Operating and maintenance expense | (26.3) | (28.6) | (2.3) | (8)% |
| Depreciation and amortization expense | (25.2) | (24.3) | 0.9 | 4% |
| General and administrative expense | (11.9) | (11.7) | 0.2 | 2% |
| Other income | 0.1 | 0.1 | — | —% |
| Earnings from unconsolidated affiliates (f) | 5.7 | 4.5 | 1.2 | 27% |
| Interest expense | (12.6) | (8.0) | 4.6 | 58% |
| Income tax expense | (0.2) | (0.3) | (0.1) | (33)% |
| Net income attributable to noncontrolling interests | (0.7) | (3.5) | (2.8) | (80)% |
| Net income attributable to partners | $ 23.3 | $ — | $ 23.3 | 100% |
| Other data: | | | | |
| Non-cash commodity derivative mark-to-market | $ (22.6) | $ (34.9) | $ 12.3 | 35% |
| Natural gas throughput (MMcf/d) (f) | 1,678 | 1,480 | 198 | 13% |
| NGL gross production (Bbls/d) (f) | 63,186 | 56,819 | 6,367 | 11% |
| NGL pipelines throughput (Bbls/d) (f) | 82,695 | 45,713 | 36,982 | 81% |
| Propane sales volume (Bbls/d) | 34,379 | 40,038 | (5,659) | (14)% |

* Percentage change is not meaningful.

(a) On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas, in our Natural Gas Services segment, for the three months ended March 31, 2012 and 2011.

(b) Includes the results of our acquisition of the remaining 49.9% interest in East Texas, since January 3, 2012, the date of acquisition, in our Natural Gas Services segment.

(c) Includes the results of our DJ Basin NGL Fractionators since the date of acquisition of March 24, 2011, in our NGL Logistics Segment.

(d) We utilize commodity derivative instruments to provide stability to distributable cash flows for our ownership in East Texas as well as all other natural gas services assets. On January 3, 2012, we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC. For the three months ended March 31, 2011, the 49.9% interest in East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 49.9% of East Texas, unhedged.

(e) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs, and segment gross margin for each segment consists of total operating revenues for that segment, less commodity purchases for that segment. Please read “Reconciliation of Non-GAAP Measures” above.

(f) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, and Discovery and our share of earnings for Discovery. Earnings for Discovery include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

(g) Operating revenues include the impact of commodity derivative activity

***Three Months Ended March 31, 2012 vs. Three Months Ended March 31, 2011***

*Total Operating Revenues* — Total operating revenues decreased in 2012 compared to 2011 primarily as a result of the following:

- $100.2 million decrease primarily attributable to lower volumes from the predecessor’s Southeast Texas storage business, differences in gas quality and lower commodity prices, which impact both sales and purchases, partially offset by increased volumes across certain assets; and
- $45.2 million decrease attributable to reduced Wholesale Propane Logistics segment volumes as a result of record warm winter weather.

These decreases were partially offset by:

- $34.9 million increase related to commodity derivative activity. This includes a decrease in unrealized losses in 2012 compared to 2011 of $12.3 million due to movements in forward prices of commodities, and realized cash settlement gains in 2012 compared to realized cash settlement losses in 2011 for a net increase of $22.6 million. Included in our derivative activity are an increase in unrealized losses of $13.1 million and an increase in realized gains of $22.3 million from the predecessor’s Southeast Texas storage business; and
- $2.2 million increase in transportation, processing and other revenue, which represents our fee-based revenues.

*Gross Margin* — Gross margin increased in 2012 compared to 2011, primarily as a result of the following:

- $17.6 million increase for our Natural Gas Services segment, primarily related to commodity derivative activity as explained in the Operating Revenues section above and increased volumes across certain assets. These increases were partially offset by lower volumes from the predecessor’s Southeast Texas storage business and differences in gas quality; and

- $5.6 million increase for our NGL Logistics segment as a result of the Wattenberg expansion project, increased throughput on our pipelines, and our acquisition of the DJ Basin NGL Fractionators.

These increases were partially offset by:

- $0.6 million decrease for our Wholesale Propane Logistics segment, due to reduced volumes as a result of record warm winter weather, partially offset by higher unit margins.

*Operating and Maintenance Expense* — Operating and maintenance expense decreased in 2012 compared to 2011 as a result of timing of expenditures, the completion of the Wattenberg capital expansion project and our acquisition of the DJ Basin NGL Fractionators.

*Depreciation and Amortization Expense* — Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

*Earnings from Unconsolidated Affiliates* — Earnings from unconsolidated affiliates increased in 2012 compared to 2011 primarily as a result of timing of operating expenses at our Discovery asset.

*Net income attributable to noncontrolling interests* — Net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of our acquisition of the remaining 49.9% of East Texas.

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***Results of Operations — Natural Gas Services Segment***

Subsequent to our East Texas and Southeast Texas acquisitions on January 3, 2012 and March 30, 2012, respectively, the 2012 operating capacity for our Natural Gas Services segment is as follows:

| 2012 Operating Data | | | | | |
|---|---|---|---|---|---|
| System | Approximate Gas Gathering and Transmission Systems (Miles) | Plants | Fractionators | Approximate Net Nameplate Plant Capacity (MMcf/d) (b) | Approximate Natural Gas Storage Capacity (Bcf) |
| Minden | 725 | 1(c) | — | 115 | — |
| Ada | 130 | 1(c) | — | 45 | — |
| Pelico | 600 | — | — | — | 1(e) |
| Southern Oklahoma | 225 | — | — | — | — |
| Colorado | 40 | 1(d) | — | 84 | — |
| Wyoming | 1,300 | — | — | — | — |
| Michigan | 440 | 4(d) | — | 455 | — |
| Discovery | 300 | 1(c)(e) | 1(e) | 240 | — |
| East Texas | 900 | 5(c)(f) | 1 | 780(a) | — |
| Southeast Texas | 675 | 3(c) | — | 400(a) | 9(a) |
| Total | 5,335 | 16 | 2 | 2,119 | 10 |

(a) Capacity and total volumes updated for 100% ownership of East Texas and Southeast Texas.
(b) Represents total capacity or total volumes allocated to our ownership share for the first quarter of 2012 divided by 91 days. We have a 40% limited liability company interest in Discovery and a 75% operating interest in our Colorado system.
(c) Represents NGL extraction plants.
(d) Represents treating plants.
(e) Represents a location operated by a third party.
(f) Our East Texas complex comprises 5 cryogenic processing plants.

This segment consists of our Northern Louisiana system, the Southern Oklahoma system, a 40% limited liability company interest in Discovery, our Southeast Texas system, a 75% operating interest in our Colorado system, our Wyoming system, our East Texas system, and our Michigan system.

| | Three Months Ended March 31, | | Variance Three Months 2012 vs. 2011 | |
|---|---|---|---|---|
| | 2012 (b) | 2011 (a)(b) | Increase (Decrease) | Percent |
| | (Millions, except as indicated) | | | |
| Operating revenues: | | | | |
| Sales of natural gas, NGLs and condensate | $ 283.9 | $384.1 | $(100.2) | (26)% |
| Transportation, processing and other | 27.9 | 28.6 | (0.7) | (2)% |
| (Losses) from commodity derivative activity | (6.1) | (39.4) | (33.3) | (85)% |
| Total operating revenues | 305.7 | 373.3 | (67.6) | (18)% |
| Purchases of natural gas and NGLs | (248.4) | (333.6) | (85.2) | (26)% |
| Segment gross margin (c) | 57.3 | 39.7 | 17.6 | 44% |
| Operating and maintenance expense | (18.3) | (21.0) | (2.7) | (13)% |
| Depreciation and amortization expense | (22.3) | (21.9) | 0.4 | 2% |
| Earnings from unconsolidated affiliates (e) | 5.7 | 4.5 | 1.2 | 27% |
| Segment net income | 22.4 | 1.3 | 21.1 | 1,623% |
| Segment net income attributable to noncontrolling interests | (0.7) | (3.5) | (2.8) | (80)% |
| Segment net income (loss) attributable to partners | $ 21.7 | $(2.2) | $ 23.9 | * |
| Other data: | | | | |
| Non-cash commodity derivative mark-to-market | $ (23.0) | $(34.6) | $ 11.6 | 34% |
| Natural gas throughput (MMcf/d) (d) | 1,678 | 1,480 | 198 | 13% |
| NGL gross production (Bbls/d) (d) | 63,186 | 56,819 | 6,367 | 11% |

* Percentage change is not meaningful.

(a) We utilize commodity derivative instruments to provide stability to distributable cash flows for our ownership in East Texas as well as all other natural gas services assets. On January 3, 2012 we acquired the remaining 49.9% interest in East Texas from DCP Midstream, LLC. For the three months ended March 31, 2011, the 49.9% interest in East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 49.9% of East Texas, unhedged.

(b) On March 30, 2012, we acquired the remaining 66.67% interest in Southeast Texas, and commodity derivative instruments related to the Southeast Texas storage business, for aggregate consideration of $240.0 million, subject to certain working capital and other customary purchase price adjustments. Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 100% interest in Southeast Texas for the three months ended March 31, 2012 and 2011.

(c) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read "Reconciliation of Non-GAAP Measures" above.

(d) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, and Discovery and our share of earnings for Discovery. Earnings for Discovery include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

***Three Months Ended March 31, 2012 vs. Three Months Ended March 31, 2011***

*Total Operating Revenues* — Total operating revenues decreased in 2012 compared to 2011, primarily as a result of the following:

- $45.2 million decrease primarily attributable to timing differences in gas quality, and lower volumes from the predecessor's Southeast Texas storage business, partially offset by increased volumes across certain assets; and
- $55.7 million decrease attributable to lower commodity prices, which impact both sales and purchases.

These decreases were partially offset by:

- $33.3 million increase related to commodity derivative activity. This includes a decrease in unrealized losses in 2012 compared to 2011 of $11.6 million due to movements in forward prices of commodities, and realized cash settlement gains in 2012 compared to realized cash settlement losses in 2011 for a net increase of $21.7 million. Included in our derivative activity are an increase in unrealized losses of $13.1 million and an increase in realized gains of $22.3 million from the predecessor's Southeast Texas storage business.

*Purchases of Natural Gas and NGLs* — Purchases of natural gas and NGLs decreased in 2012 compared to 2011 primarily as a result of lower commodity prices, which impact both purchases and sales and timing of storage earnings recognition.

*Segment Gross Margin* — Segment gross margin increased in 2012 compared to 2011, primarily as a result of the following:

- $33.3 million increase related to commodity derivative activities as discussed in the Operating Revenues section above.

  This increase was partially offset by:

- $15.7 million decrease primarily attributable to differences in gas quality, and lower volumes from the predecessor's Southeast Texas storage business, partially offset by increased volumes across certain assets.

*Operating and Maintenance Expense* — Operating and maintenance expense decreased in 2012 compared to 2011 as a result of timing of expenditures.

*Depreciation and Amortization Expense* — Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

*Earnings from Unconsolidated Affiliates* — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, increased in 2012 compared to 2011 primarily as a result of timing of operating expenses. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

*Segment net income attributable to noncontrolling interests* — Segment net income attributable to noncontrolling interests decreased in 2012 compared to 2011 as a result of the acquisition of our remaining 49.9% of East Texas.

*Natural Gas Throughput* — Natural gas transported, processed and/or treated increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, partially offset by reduced volumes on our Pelico system.

*NGL Gross Production* — NGL production increased in 2012 compared to 2011 primarily as a result of our acquisition of the remaining 49.9% of East Texas, partially offset by differences in gas quality.

***Results of Operations — NGL Logistics Segment***

This segment includes our Seabreeze, Wilbreeze, Wattenberg and Black Lake transportation pipelines, our Marysville NGL storage facility and our DJ Basin NGL Fractionators:

| | Three Months Ended March 31, | | Variance Three Months 2012 vs. 2011 | |
|---|---|---|---|---|
| | **2012 (b)** | **2011(b)** | **Increase (Decrease)** | **Percent** |
| Operating revenues: | | | | |
| Sales of NGLs | $ — | $ 4.8 | $ (4.8) | (100)% |
| Transportation, processing and other | 15.9 | 10.2 | 5.7 | 56% |
| Total operating revenues | 15.9 | 15.0 | 0.9 | 6% |
| Purchases of NGLs | — | (4.7) | (4.7) | (100)% |
| Segment gross margin (a) | 15.9 | 10.3 | 5.6 | 54% |
| Operating and maintenance expense | (4.2) | (4.0) | 0.2 | 5% |
| Depreciation and amortization expense | (2.2) | (1.7) | 0.5 | 29% |
| Other income | 0.1 | 0.1 | — | — % |
| Segment net income attributable to partners | $ 9.6 | $ 4.7 | $ 4.9 | 104% |
| Other data: | | | | |
| NGL pipelines throughput (Bbls/d) | 82,695 | 45,713 | 36,982 | 81% |

(a) Segment gross margin consists of total operating revenues less purchases of NGLs. Please read “Reconciliation of Non-GAAP Measures” above.
(b) Includes the results of our DJ Basin NGL Fractionators since the date of acquisition of March 24, 2011.

***Three Months Ended March 31, 2012 vs. Three Months Ended March 31, 2011***

*Total Operating Revenues* — Total operating revenues increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project, increased throughput on our pipelines and our acquisition of the DJ Basin NGL Fractionators.

*Segment Gross Margin* — Segment gross margin increased in 2012 compared to 2011 as result of the completion of the Wattenberg capital expansion project, increased throughput on our pipelines and our acquisition of the DJ Basin NGL Fractionators.

*Operating and Maintenance Expense* — Operating and maintenance expense increased in 2012 compared to 2011as a result of the completion of the Wattenberg capital expansion project and our acquisition of the DJ Basin NGL Fractionators.

*Depreciation and Amortization Expense* — Depreciation and amortization expense increased in 2012 compared to 2011 as a result of our acquisition of the DJ Basin NGL Fractionators and the Wattenberg capital expansion project.

*NGL Pipelines Throughput* — NGL pipelines throughput increased in 2012 compared to 2011as a result of volume growth on our pipelines and the completion of the Wattenberg capital expansion project.

***Results of Operations — Wholesale Propane Logistics Segment***

This segment consists of our propane terminals, which include six owned and operated rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals.

| | Three Months Ended March 31, | | Variance Three Months 2012 vs. 2011 | |
|---|---|---|---|---|
| | 2012 | 2011 | Increase (Decrease) | Percent |
| | (Millions, except as indicated) | | | |
| Operating revenues: | | | | |
| Sales of propane | $ 203.2 | $ 248.4 | $ (45.2) | (18)% |
| Other | — | 0.2 | (0.2) | (100)% |
| Gains (losses) from commodity derivative activity | 0.8 | (0.8) | 1.6 | * |
| Total operating revenues | 204.0 | 247.8 | (43.8) | (18)% |
| Purchases of propane | (182.8) | (226.0) | (43.2) | (19)% |
| Segment gross margin (a) | 21.2 | 21.8 | (0.6) | (3)% |
| Operating and maintenance expense | (3.8) | (3.6) | 0.2 | 6% |
| Depreciation and amortization expense | (0.7) | (0.7) | — | — % |
| Segment net income attributable to partners | $ 16.7 | $ 17.5 | $ (0.8) | (5)% |
| Other data: | | | | |
| Non-cash commodity derivative mark-to-market | $ 0.4 | $ (0.3) | $ 0.7 | * |
| Propane sales volume (Bbls/d) | 34,379 | 40,038 | (5,659) | (14)% |

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read “Reconciliation of Non-GAAP Measures” above.

***Three Months Ended March 31, 2012 vs. Three Months Ended March 31, 2011***

*Total Operating Revenues* — Total operating revenues decreased in 2012 compared to 2011, primarily as a result of the following:

- $42.7 million decrease attributable to reduced volumes primarily as a result of record warm winter weather; and
- $2.7 million decrease attributable to lower propane prices, which impacts both purchases and sales.

These decreases were partially offset by:

- $1.6 million increase related to related to commodity derivative activity.

*Purchases of Propane* — Purchases of propane decreased in 2012 compared to 2011 primarily due to reduced volumes as a result of record warm winter weather and lower propane prices, which impact both sales and purchases.

*Segment Gross Margin* — Segment gross margin decreased slightly in 2012 compared to 2011 due to reduced volumes as a result of record warm winter weather, partially offset by higher unit margins.

*Operating and Maintenance Expense* — Operating and maintenance expense remained relatively constant in 2012 compared to 2011.

*Depreciation and Amortization Expense* — Depreciation and amortization expense remained relatively constant in 2012 compared to 2011.

*Propane Sales Volume* — Propane sales volumes decreased in 2012 compared to 2011 due to tempered demand as a result of record warm winter weather.

**Liquidity and Capital Resources**

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our revolving credit facility;
- issuance of additional partnership units;
- debt offerings;
- guarantees issued by DCP Midstream, LLC, which reduce the amount of collateral we may be required to post with certain counterparties to our commodity derivative instruments; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- capital expenditures;
- quarterly distributions to our unitholders;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions; and
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements, and which is required to the extent we exceed certain guarantees issued by DCP Midstream, LLC and letters of credit we have posted.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months. In the event these sources are not sufficient, we would reduce our discretionary spending.

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we obtain additional capital, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities and acquisitions.

Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our business, although deterioration in our operating environment could limit our borrowing capacity, raise our financing costs, as well as impact our compliance with our financial covenant requirements under our Credit Agreement. Our sources of funding could include additional borrowings under our Credit Agreement, the placement of public and private debt, and the issuance of our common units.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2016 with fixed price commodity swaps and collar arrangements. For additional information regarding our derivative activities, please read “Item7A. Quantitative and Qualitative Disclosures about Market Risk” in our 2011 Form 10-K and “Item 3. Quantitative and Qualitative Disclosures about Market Risk” in this Quarterly Report on Form 10-Q.

Our Credit Agreement consists of a senior unsecured revolving credit facility with capacity of $1.0 billion, which matures on November 10, 2016. Our borrowing capacity is currently limited by the Credit Agreement’s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under the Credit Agreement will not mature prior to the November 10, 2016 maturity date. As of May 4, 2012, we had approximately $643.9 million of unused capacity under the Credit Agreement.

On January 3, 2012, we entered into a 2-year Term Loan Agreement with Wells Fargo Bank, National Association, SunTrust Bank and The Bank of Tokyo-Mitsubishi UFJ, Ltd. as lenders. We borrowed $135.0 million under the term loan on January 3, 2012, which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

On March 13, 2012, we issued $350.0 million of 4.95% 10-year Senior Notes due April 1, 2022. We received proceeds of $345.8 million, which are net of underwriters' fees, related expenses and unamortized, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Facility.

In January 2012, we issued 727,520 common units to DCP Midstream, LLC as partial consideration for the remaining 49.9% interest in East Texas.

In March 2012, we issued 1,000,417 common units to DCP Midstream, LLC as partial consideration for the remaining 66.67% interest in Southeast Texas.

In March 2012, we issued 5,148,500 common limited partner units at $47.42 per unit. We received proceeds of $234.2 million, net of offering costs.

The counterparties to each of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. As of May 4, 2012, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $70.0 million in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. We pay DCP Midstream, LLC a fee of 0.50% per annum on these guarantees. As of May 4, 2012, we had a contingent letter of credit facility for up to $10.0 million, on which we pay a fee of 0.50% per annum. As of May 4, 2012, we had no letters of credit issued on this facility; we will pay a net fee of 1.75% per annum on letters of credit issued on this facility. This contingent letter of credit facility was issued directly by a financial institution and does not reduce the available capacity under our credit facility. These parental guarantees and contingent letter of credit facility reduce the amount of cash we may be required to post as collateral. As of May 4, 2012, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for commodity derivative instruments guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC's credit rating and the thresholds would be reduced to zero in the event DCP Midstream, LLC's credit rating were to fall below investment grade.

***Working Capital*** — Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, inventory levels, and other business factors that affect our net income and cash flows. Our working capital is also impacted by the timing of operating cash receipts and disbursements, borrowings of and payments on debt, capital expenditures, and increases or decreases in restricted investments and other long-term assets.

We had a working capital deficit of $13.1 million as of March 31, 2012, compared to a working capital deficit of $26.8 million as of December 31, 2011. Included in these working capital amounts are net derivative working capital liabilities of $14.4 million and $18.7 million as of March 31, 2012 and December 31, 2011, respectively. The change in working capital is primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of March 31, 2012, we had $6.1 million in cash and cash equivalents. Of this balance, as of March 31, 2012, $2.9 million was held by subsidiaries we do not wholly own, which we consolidate in our financial results. Other than the cash held by these subsidiaries, this cash balance was available for general corporate purposes. In 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which has the potential to impact our cash collateral and reporting requirements for our derivative positions depending on the final regulations adopted by the United States Commodity Futures Trading Commission and the U.S. Securities and Exchange Commission.

***Cash Flow*** — Operating, investing and financing activities was as follows:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2012 | 2011 |
| | (Millions) | |
| Net cash provided by operating activities | $ 61.0 | $ 92.7 |
| Net cash used in investing activities | $(365.2) | $(184.4) |
| Net cash provided by financing activities | $ 302.7 | $ 92.1 |

Our predecessor’s sources of liquidity, prior to its acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our predecessor’s cash receipts were deposited in DCP Midstream, LLC’s bank accounts and all cash disbursements were made from these accounts. Cash transactions for our predecessor were handled by DCP Midstream, LLC and were reflected in partners’ equity as net changes in parent advances to predecessors from DCP Midstream, LLC.

*Net Cash Provided by Operating Activities* — The changes in net cash provided by operating activities are attributable to our net income adjusted for non-cash charges as presented in the condensed consolidated statements of cash flows and changes in working capital as discussed above.

We received $21.0 million for our net hedge cash settlements related to the Southeast Texas storage business, offset by $3.7 million in other net cash hedge settlements paid, for the three months ended March 31, 2012. We received $1.3 million for our net hedge cash settlements related to the Southeast Texas storage business, offset by $6.6 million in other net cash hedge settlements paid, for the three months ended March 31, 2011.

We received cash distributions from unconsolidated affiliates of $5.6 million and $5.6 million during the three months ended March 31, 2012 and 2011, respectively. Earnings exceeded distributions by $0.1 million for the three months ended March 31, 2012, and distributions exceeded earnings by $1.1 million for the three months ended March 31, 2011.

*Net Cash Used in Investing Activities* — Net cash used in investing activities during the three months ended March 31, 2012 was comprised of: (1) acquisition expenditures of $311.4 million, of which $189.0 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, and $122.4 million related to our acquisition of the remaining 49.9% interest in East Texas ; (2) capital expenditures of $53.4 million (our portion of which was $48.3 million and the reimbursable projects portion was $5.1 million); (3) investments in unconsolidated affiliates of $1.5 million; partially offset by (4) return of investment from unconsolidated affiliate of $1.0 million; and (5) proceeds from sales of assets of $0.1 million.

Net cash used in investing activities during the three months ended March 31, 2011 was comprised of: (1) acquisition expenditures of $29.7 million related to our acquisition of our DJ Basin NGL Fractionators; (2) acquisition expenditures of $114.2 million, related to our acquisition of Southeast Texas; (3) payment of $7.5 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; (4) capital expenditures of $33.1 million (our portion of which was $29.6 million and the noncontrolling interest holders’ portion was $3.5 million); and (5) investments in unconsolidated affiliates of $0.1 million; partially offset by (6) proceeds from sales of assets of $0.2 million.

*Net Cash Provided by Financing Activities* — Net cash provided by financing activities during the three months ended March 31, 2012 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $234.2 million; (2) contributions from DCP Midstream, LLC of $2.7 million; and (3) proceeds from debt of $722.4 million, including $350.0 million from the issuance of our 4.95% 10-year Senior Notes, offset by borrowings of $604.0 million, for net borrowing of debt of $118.4 million; partially offset by (4) distributions to our unitholders and general partner of $36.7 million; (5) net change in advances to predecessor from DCP Midstream, LLC of $11.5 million; (6) distributions to noncontrolling interests of $1.7 million; and (7) payment of deferred financing costs of $2.7 million.

Net cash provided by financing activities during the three months ended March 31, 2011 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $139.7 million; (2) contributions from DCP Midstream, LLC of $2.9 million; and (3) net borrowing of debt of $28.0 million; partially offset by (4) distributions to our unitholders and general partner of $30.1 million; (5) distributions to noncontrolling interests of $5.4 million; (6) excess purchase price over the acquired net assets of Southeast Texas of $35.7 million; (7) net change in advances to predecessor from DCP Midstream, LLC of $7.2 million; and (8) payment of deferred financing costs of $0.1 million.

During the three months ended March 31, 2012, total outstanding indebtedness under our $1.0 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than $268.1 million and did not exceed $576.1 million. The weighted-average indebtedness outstanding for the three months ended March 31, 2012 was $495.8 million.

We had unused revolver capacity, which is available commitments under the Credit Agreement, of $731.9 million as of March 31, 2012.

During the three months ended March 31, 2012, we had the following net movements on our revolving credit facility:

- $234.2 million repayment financed by the issue of 5,148,500 common units in March 2012; and
- $23.0 million repayment financed by the issue of $350.0 million of 4.95% Senior Notes due April 1, 2022; partially offset by
- $27.2 million net borrowings.

During the three months ended March 31, 2011, we had the following net movements on our revolving credit facility:

- $139.7 million repayment financed by the issue of 3,596,636 common units in March 2011; and
- $12.3 million net repayments; partially offset by
- $150.0 million borrowing to fund the acquisition of our 33.33% interest in Southeast Texas; and
- $30.0 million borrowing to fund the purchase of the DJ Basin NGL Fractionators.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 12 of the Notes to Condensed Consolidated Financial Statements in Item 1. “Financial Statements.”

***Capital Requirements*** — The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

- maintenance capital expenditures, which are cash expenditures where we add on to or improve capital assets owned, including certain system integrity and safety improvements, or acquire or construct new capital assets if such expenditures are made to maintain, including over the long-term, our operating or earnings capacity; and
- expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating or earnings capacity.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $15.0 million and $20.0 million, and expenditures for expansion capital of between $300.0 million and $360.0 million, for the year ending December 31, 2012. Expansion capital expenditures include construction of the Eagle Plant, construction of the Texas Express Pipeline and Discovery's Keathley Canyon, which are shown as investments in unconsolidated affiliates, expansion and upgrades to our East Texas complex, and acquisition integration projects. The board of directors may approve additional growth capital during the year, at their discretion.

The following table summarizes our maintenance and expansion capital expenditures for our consolidated entities.

| | Three Months Ended March 31, 2012 | | | Three Months Ended March 31, 2011 | | |
|---|---|---|---|---|---|---|
| | Maintenance Capital Expenditures | Expansion Capital Expenditures | Total Consolidated Capital Expenditures | Maintenance Capital Expenditures | Expansion Capital Expenditures | Total Consolidated Capital Expenditures |
| | | (Millions) | | | (Millions) | |
| Our portion | $ 3.3 | $ 45.0 | $ 48.3 | $ 2.0 | $ 27.6 | $ 29.6 |
| Noncontrolling interest portion and reimbursable projects (a) | 2.3 | 2.8 | 5.1 | 1.2 | 2.3 | 3.5 |
| Total | $ 5.6 | $ 47.8 | $ 53.4 | $ 3.2 | $ 29.9 | $ 33.1 |

(a) In conjunction with our acquisitions of our East Texas and Southeast Texas systems, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse us for certain expenditures on capital projects. These reimbursements are for certain capital projects which have commenced within three years from the respective acquisition dates.

In addition, we invested cash in unconsolidated affiliates of $1.5 million and $0.1 million during the three months ended March 31, 2012 and 2011 to fund our share of capital expansion projects.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, which will include debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units and the issuance of long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

***Cash Distributions to Unitholders*** — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $36.7 million during the three months ended March 31, 2012, as compared to $30.1 million for the same period in 2011. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

***Description of the Credit Agreement*** — The Credit Agreement consists of a $1.0 billion revolving credit facility that matures November 10, 2016. As of March 31, 2012, the outstanding balance on the revolving credit facility was $267.0 million resulting in unused revolver capacity of $731.9 million, of which approximately $591.1 million was available for general working capital purposes.

Our obligations under the revolving credit facility are unsecured. The unused portion of the revolving credit facility may be used for letters of credit. At March 31, 2012 and December 31, 2011, we had $1.1 million and $1.1 million, respectively, outstanding letters of credit issued under the Credit Agreement.

As of March 31, 2012, the weighted-average interest rate on our revolving credit facility was 1.56% per annum, excluding the impact of interest rate swaps.

***Description of the Term Loan Agreement*** — On January 3, 2012, we entered into a 2-year Term Loan Agreement with Wells Fargo Bank, National Association, SunTrust Bank and The Bank of Tokyo-Mitsubishi UFJ, Ltd. as lenders. We borrowed $135.0 million under the term loan on January 3, 2012, which was used to fund the cash portion of the acquisition of the remaining 49.9% interest in East Texas. In March 2012, we repaid the term loan with proceeds from our 4.95% 10-year Senior Notes.

***Description of Debt Securities*** — On March 13, 2012, we issued $350.0 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of $345.8 million, net of underwriters' fees, related expenses and unamortized discounts of $2.3 million, $0.3 million and $1.6 million, respectively, which we used to fund the cash portion of the acquisition of the remaining 66.67% interest in Southeast Texas and to repay funds borrowed under our Term Loan and Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2012. The notes will mature on April 1, 2022, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

On September 30, 2010, we issued $250.0 million of our 3.25% 5-year Senior Notes due October 1, 2015. We received net proceeds of $247.7 million, net of underwriters' fees, related expenses and unamortized discounts of $1.5 million, $0.6 million and $0.2 million, respectively which we used to repay funds borrowed under the revolver portion of our Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing April 1, 2011. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

Both series of notes are senior unsecured obligations, ranking equally in right of payment with our existing unsecured indebtedness, including indebtedness under our Credit Facility. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option.

***Total Contractual Cash Obligations and Off-Balance Sheet Obligations***

A summary of our total contractual cash obligations as of March 31, 2012, is as follows:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 year | 1-3 years | 3-5 years | Thereafter |
| | | | (Millions) | | |
| Long-term debt (a) | $1,092.3 | $ 25.6 | $ 59.6 | $560.4 | $ 446.7 |
| Operating lease obligations (b) | 27.0 | 12.0 | 11.2 | 2.8 | 1.0 |
| Purchase obligations (c) | 235.2 | 81.6 | 80.5 | 73.1 | — |
| Other long-term liabilities (d) | 17.1 | — | 0.5 | 0.2 | 16.4 |
| Total | $1,371.6 | $ 119.2 | $151.8 | $636.5 | $ 464.1 |

(a) Includes interest payments on long-term debt that has been hedged and on debt securities that have been issued. Interest payments on long-term debt that has not been hedged are not included as these payments are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Our operating lease obligations are contractual obligations, and primarily consist of our leased marine propane terminal and railcar leases, both of which provide supply and storage infrastructure for our Wholesale Propane Logistics business. Operating lease obligations also include natural gas storage for our Pelico system. The natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the futures market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index, the amount is based on the forward market prices as of March 31, 2012. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the condensed consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the condensed consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(d) Other long-term liabilities include $16.1 million of asset retirement obligations and $1.0 million of environmental reserves recognized in the March 31, 2012 condensed consolidated balance sheet.

We have no items that are classified as off balance sheet obligations.

### Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-04 "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs",* or ASU 2011-04** — In May 2011, the FASB issued ASU 2011-04 which amends Accounting Standards Codification, Topic 820 "Fair Value Measurements and Disclosures" to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB's intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 became effective for us for interim and annual periods beginning after December 15, 2011. The provisions of ASU 2011-04 impact only disclosures and we have disclosed information in accordance with the provisions of ASU 2011-04 within this filing.

## Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

For an in-depth discussion of our market risks, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" in our 2011Form 10-K.

### *Credit Risk*

Our principal customers in the Natural Gas Services segment are large, natural gas marketers and industrial end-users. Our principal customers in the Wholesale Propane Logistics segment are primarily retail propane distributors. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, as these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

### *Interest Rate Risk*

Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

We mitigate a portion of our interest rate risk with interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2011, we had interest rate swap agreements totaling $450.0 million, of which we had designated $425.0 million as cash flow hedges and accounted for the remaining $25.0 million under the mark-to-market method of accounting. In March 2012, we paid down a portion of the revolving credit facility and as a result, we discontinued cash flow hedge accounting on $225.0 million of our interest rate swap agreements.

At March 31, 2012, we had interest rate swap agreements totaling $450.0 million, of which we have designated $200.0 million as cash flow hedges and account for the remaining $250.0 million under the mark-to-market method of accounting. As of May 4, 2012, we had interest rate swap agreements totaling $300.0 million, of which we have designated $200.0 million as cash flow hedges and account for the remaining $100.0 million under the mark-to-market method of accounting. $150.0 million of these agreements extend through June 2012, and $150.0 million extending through June 2014. Based on our current operations we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt.

Effectiveness of our interest rate swap agreements designated as cash flow hedges is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. Ineffective portions of changes in fair value are recognized in earnings.

At March 31, 2012, the effective weighted-average interest rate on our outstanding debt was 4.37%, taking into account our interest rate swap agreements designated as cash flow hedges totaling $200.0 million.

Based on our interest rate swap agreements with no offsetting debt position of $183.0 million as of March 31, 2012, a 0.5% movement in the base rate or LIBOR rate result in an approximately $0.9 million annualized increase or decrease in interest expense. $300.0 million of our interest rate swap agreements at March 31, 2012 mature in June 2012.

***Commodity Price Risk***

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing and storage services, we either receive fees or commodities as payment for these services, depending on the types of contracts. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps, costless collars and futures.

*Commodity Cash Flow Protection Activities* — We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various fixed price swaps and collar arrangements to mitigate a portion of the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

We enter into derivative financial instruments to mitigate a portion of the cash flow risk of decreased natural gas, NGL and condensate prices associated with our percent-of-proceeds arrangements and gathering operations. We also may enter into natural gas derivatives to lock in margin around our transportation or leased storage assets. Historically, there has been a strong relationship between NGL prices and crude oil prices, with some recent exceptions. Given the limited liquidity and tenor of the NGL financial market, we have historically used crude oil swaps and costless collars to mitigate a portion of our NGL price risk. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship where we utilize crude oil swaps and costless collars to mitigate NGL price exposure. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps, a portion of which are with DCP Midstream, LLC. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk through 2016.

The derivative financial instruments we have entered into are typically referred to as “swap” contracts and “collar” arrangements. The swap contracts entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment at settlement to the counterparty to the extent that the reference price is higher than the swap price stated in the contract.

We also use commodity collar arrangements, which entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the floor price stated in the contract. Conversely, if the reference price is above the ceiling price stated in the contract, we are required to make payment at settlement to the counterparty. If the reference price is between the floor price and the ceiling price, no payment will be made at the settlement of the contract.

We are using the mark-to-market method of accounting for all commodity derivative instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on derivative activity.

The following tables set forth additional information about our fixed price swaps, and our collar arrangements used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations, as of May 4, 2012:

**Commodity Swaps**

| Period | Commodity | Notional Volume - (Short)/Long Positions | Reference Price | Price Range |
|---|---|---|---|---|
| April 2012 — December 2012 | Natural Gas | (1,181) MMBtu/d | Monthly Average for Carthage Gas Daily Daily (e) | $4.34/MMBtu |
| April 2012 — December 2014 | Natural Gas | (500) MMBtu/d | IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a) | $5.06/MMBtu |
| April 2012 — December 2014 | Natural Gas | (1,000) MMBtu/d | Texas Gas Transmission Price (b) | $4.87/MMBtu |
| April 2012 — December 2012 | NGL's | (2,463) Bbls/d | Mt.Belvieu Non-TET (d) | $.90-$2.60/Gal |
| January 2013 — December 2013 | NGL's | (1,715) Bbls/d | Mt.Belvieu Non-TET (d) | $.90-$2.60/Gal |
| January 2014 — March 2015 | NGL's | (1,725) Bbls/d | Mt.Belvieu Non-TET (d) | $.90-$2.60/Gal |
| April 2012 — December 2012 | NGL's | (702) Bbls/d | Mt.Belvieu Non-TET (d) | $2.20/Gal |
| April 2012 — December 2012 | Crude Oil | (2,325) Bbls/d | Asian-pricing of NYMEX crude oil futures (c) | $66.72 - $99.85/Bbl |
| January 2013 — December 2013 | Crude Oil | (2,250) Bbls/d | Asian-pricing of NYMEX crude oil futures (c) | $67.60 - $99.85/Bbl |
| January 2014 — December 2014 | Crude Oil | (1,500) Bbls/d | Asian-pricing of NYMEX crude oil futures (c) | $74.90 - $96.08/Bbl |
| January 2015 — December 2015 | Crude Oil | (1,000) Bbls/d | Asian-pricing of NYMEX crude oil futures (c) | $92.00-$100.04/Bbl |
| January 2016 — December 2016 | Crude Oil | (500) Bbls/d | Asian-pricing of NYMEX crude oil futures (c) | $101.30/Bbl |
| April 2012 — December 2014 | Natural Gas | 500 MMBtu/d | Texas Gas Transmission Price (b) | $4.93/MMBtu |
| April 2012 — December 2012 | Crude Oil | 700 Bbls/d | Asian-pricing of NYMEX crude oil futures (c) | $92.00/Bbl |

(a) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.
(b) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.
(c) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(d) The average monthly OPIS price for Mt. Belvieu Non-TET.
(e) The average monthly gas price for Carthage Gas Daily Daily.

**Commodity Collar Arrangements**

| Period | Commodity | Notional Volume | Reference Price | Collar Price Range |
|---|---|---|---|---|
| April 2012 — December 2012 | Crude Oil | 600 Bbls/d (a) | Asian-pricing of NYMEX crude oil futures (b) | $80.00 - $97.40/Bbl |
| January 2013 — December 2013 | Crude Oil | 400 Bbls/d (a) | Asian-pricing of NYMEX crude oil futures (b) | $80.00 - $96.50/Bbl |

(a) Reflects separate purchased put and sold call contracts, resulting in a collar arrangement.
(b) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

Our sensitivities for 2012 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2012, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize crude oil and NGL derivatives to mitigate a portion of our commodity price exposure for NGLs, and show our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes.

**Commodity Sensitivities Excluding Non-Cash Mark-To-Market**

| | Per Unit Decrease | Unit of Measurement | Estimated Decrease in Annual Net Income Attributable to Partners (Millions) |
|---|---|---|---|
| Natural gas prices | $ 1.00 | MMBtu | $ 1.7 |
| Crude oil prices (a) | $ 5.00 | Barrel | $ 3.6 |
| NGL to crude oil price relationship (b) | 5 percentage point change | Barrel | $ 7.2 |

(a) Assuming 60% NGL to crude oil price relationship. At crude oil prices outside of our collar range of approximately $80.00 to $97.40, this sensitivity decreases by $0.8 million.

(b) Assuming 60% NGL to crude oil price relationship and $90.00 /Bbl crude oil price. Generally, this sensitivity changes by $0.8 million for each $10.00/Bbl change in the price of crude oil. As crude oil prices increase from $90.00 /Bbl, we become slightly more sensitive to the change in the relationship of NGL prices to crude oil prices. As crude oil prices decrease from $90.00 /Bbl, we become less sensitive to the change in the relationship of NGL prices to crude oil prices.

In addition to the linear relationships in our commodity sensitivities above, additional factors cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a certain percentage of liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as NGL prices decline.

The above sensitivities exclude the impact from arrangements where producers on a monthly basis may elect to not process their natural gas in which case we retain a portion of the customers' natural gas in lieu of NGLs as a fee. The above sensitivities also exclude certain related processing arrangements where we control the processing or by-pass of the production based upon individual economic processing conditions. Under each of these types of arrangements, our processing of the natural gas would yield favorable processing margins. Less than 10% of our gas throughput is associated with these arrangements.

We estimate the following non-cash sensitivities in 2012 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

**Non-Cash Mark-To-Market Commodity Sensitivities**

| | Per Unit Increase | Unit of Measurement | Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners) (Millions) |
|---|---|---|---|
| Natural gas prices | $ 1.00 | MMBtu | $ 1.3 |
| Crude oil prices | $ 5.00 | Barrel | $ 11.8 |
| NGL prices | $ 0.10 | Gallon | $ 9.6 |

While the above commodity price sensitivities are indicative of the impact that changes in commodity prices may have on our annualized net income, changes during certain periods of extreme price volatility and market conditions or changes in the relationship of the price of NGLs and crude oil may cause our commodity price sensitivities to vary significantly from these estimates.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2016.

Given the historical relationship between NGL prices and crude oil prices and the limited liquidity and tenor of the NGL financial market, we have generally used crude oil derivative instruments to mitigate a portion of NGL price risk. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship where we utilize crude oil swaps to mitigate NGL price exposure. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps.

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. We believe that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and imports of liquid natural gas, or LNG, from foreign locations. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also further reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

***Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program*** — Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

The following tables set forth additional information about our derivative instruments used to mitigate a portion of our natural gas price risk associated with our Southeast Texas storage operations, as of March 31, 2012:

**Inventory**

| Period | Commodity | Notional Volume - (Short)/Long Positions | Fair Value (millions) | Weighted Average Price |
|---|---|---|---|---|
| March 31, 2012 | Natural Gas | 7,592,222 MMBtu’s | $ 16.0 | $2.10/MMBtu |

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**Commodity Swaps**

| Period | Commodity | Notional Volume - (Short)/Long Positions | Fair Value (millions) | Price Range |
|---|---|---|---|---|
| April 2012 - November 2012 | Natural Gas | (32,232,500) MMBtu | $ 17.4 | $2.27-$4.33/MMBtu |
| January 2013 – October 2013 | Natural Gas | (7,000,000) MMBtu | $ 0.5 | $3.29-$3.61/MMBtu |
| April 2012 - November 2012 | Natural Gas | 25,937,500 MMBtu | $ (11.6) | $2.18-$4.50/MMBtu |
| October 2013 - November 2013 | Natural Gas | 5,500,000 MMBtu | $ (0.1) | $3.48-$3.77/MMBtu |

**Item 4.** ***Controls and Procedures***

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

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission’s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of March 31, 2012, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of March 31, 2012, our disclosure controls and procedures were effective.

***Changes in Internal Control Over Financial Reporting***

There were no changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2012 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## PART II. OTHER INFORMATION

**Item 1.** ***Legal Proceedings***

The information required for this item is provided in Note 17, “Commitments and Contingent Liabilities,” included in Item 8 of our 2011 Form 10-K, which is incorporated by reference into this item.

**Item 1A.** ***Risk Factors***

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, “Item 1A. Risk Factors” in our 2011 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2011 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our condensed consolidated results of operations, financial condition and cash flows.

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**Item 6.** ***Exhibits***

**Exhibits**

| Exhibit Number | Description |
|---|---|
| 2.1 * | Contribution Agreement among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP dated February 27, 2012 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 1, 2012). |
| 2.2 * | First Amendment to Contribution Agreement among DCP LP Holdings, LLC, DCP Midstream, LLC, and DCP Midstream Partners, LP dated March 30, 2012 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 5, 2012). |
| 3.1 * | First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP (attached as Exhibit 3.4 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005). |
| 3.2 * | First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC (attached as Exhibit 3.6 to DCP Midstream Partners, LP's Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005). |
| 3.3 * | Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006). |
| 3.4 * | Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009). |
| 3.5 * | Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP, dated as of April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008). |
| 3.6 * | Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009). |
| 4.1 * | Second Supplemental Indenture by and among DCP Midstream Operating, LP, DCP Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A. dated March 13, 2012 (attached as Exhibit 4.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 13, 2012). |
| 10.1 * | Fourteenth Amendment to the Omnibus Agreement among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP dated March 30, 2012 (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 5, 2012). |
| 10.2 * | Term Loan Agreement among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wells Fargo, National Association as Administrative Agent dated January 3, 2012 (attached as Exhibit 10.2 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2012). |
| 10.3 * | DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.26 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 10.4 * | Form of Phantom Unit and DERs Grant for Directors under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.27 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 10.5 * | Form of Performance Phantom Unit Grant Agreement and DERs Grant for Officers/Employees under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.28 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 10.6 * | Form of Restricted Phantom Unit Grant Agreement and DERs Grant under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.29 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 12.1 | Ratio of Earnings to Fixed Charges. |
| 31.1 | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |

| | |
|---|---|
| 31.2 | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101 | Financial statements from the Quarterly Report on Form 10-Q of DCP Midstream Partners, LP for the three months ended March 31, 2012, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity and (vi) the Notes to the Condensed Consolidated Financial Statements. |

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

## 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, in the City of Denver, State of Colorado, on May 10, 2012.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
*its General Partner*

By: DCP Midstream GP, LLC
*its General Partner*

By: /s/ Mark A. Borer
Name: Mark A. Borer
Title: Chief Executive Officer

By: /s/ Angela A. Minas
Name: Angela A. Minas
Title: Vice President and Chief Financial Officer
(Principal Financial Officer)

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## EXHIBIT INDEX

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| 10.2 * | Term Loan Agreement among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wells Fargo, National Association as Administrative Agent dated January 3, 2012 (attached as Exhibit 10.2 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2012). |
| 10.3 * | DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.26 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 10.4 * | Form of Phantom Unit and DERs Grant for Directors under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.27 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 10.5 * | Form of Performance Phantom Unit Grant Agreement and DERs Grant for Officers/Employees under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.28 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 10.6 * | Form of Restricted Phantom Unit Grant Agreement and DERs Grant under the DCP Midstream Partners, LP 2012 Long-Term Incentive Plan (attached as Exhibit 10.29 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 29, 2012). |
| 12.1 | Ratio of Earnings to Fixed Charges. |
| 31.1 | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |

| | |
|---|---|
| 32.1 | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101 | Financial statements from the Quarterly Report on Form 10-Q of DCP Midstream Partners, LP for the three months ended March 31, 2012, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity and (vi) the Notes to the Condensed Consolidated Financial Statements. |

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

Exhibit 12.1

## RATIO OF EARNINGS TO FIXED CHARGES

The table below sets forth the calculation of Ratios of Earnings to Fixed Charges.

| | DCP Midstream Partners, LP | | | | | |
|---|---|---|---|---|---|---|
| | Three Months Ended March 31, | Year Ended December 31, | | | | |
| | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 |
| | | (Millions) | | | | |
| **Earnings from continuing operations before fixed charges** | | | | | | |
| Pretax income (loss) from continuing operations before earnings from unconsolidated affiliates | $ 17.8 | $ 98.6 | $ 69.0 | $(11.4) | $159.2 | $ 8.9 |
| Fixed charges | 13.8 | 36.0 | 29.9 | 30.3 | 33.6 | 27.0 |
| Amortization of capitalized interest | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | — |
| Distributed earnings from unconsolidated affiliates | 5.6 | 22.7 | 23.8 | 18.6 | 18.2 | 23.5 |
| Less: | | | | | | |
| Capitalized interest | (1.2) | (1.6) | (0.2) | (1.3) | (0.3) | (0.2) |
| Earnings from continuing operations before fixed charges | $ 36.2 | $ 155.9 | $122.6 | $ 36.3 | $210.8 | $59.2 |
| **Fixed charges** | | | | | | |
| Interest expense, net of capitalized interest | $ 12.2 | $ 33.2 | $ 28.8 | $ 28.3 | $ 32.6 | $26.0 |
| Capitalized interest | 1.2 | 1.6 | 0.2 | 1.3 | 0.3 | 0.2 |
| Estimate of interest within rental expense | 0.1 | 0.5 | 0.6 | 0.5 | 0.5 | 0.6 |
| Amortization of deferred loan costs | 0.3 | 0.7 | 0.3 | 0.2 | 0.2 | 0.2 |
| Total fixed charges | $ 13.8 | $ 36.0 | $ 29.9 | $ 30.3 | $ 33.6 | $27.0 |
| Ratio of earnings to fixed charges | 2.62 | 4.33 | 4.10 | 1.20 | 6.27 | 2.19 |

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or loss from continuing operations before earnings from unconsolidated affiliates, plus fixed charges, plus distributed earnings from unconsolidated affiliates, less capitalized interest. Fixed charges consist of interest expensed, capitalized interest, amortization of deferred loan costs, and an estimate of the interest within rental expense.

**Exhibit 31.1**

**Certification Pursuant to**
**Section 302 of the Sarbanes-Oxley Act of 2002**

I, Mark A. Borer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three months ended March 31, 2012;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2012

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer

**Exhibit 31.2**

**Certification Pursuant to**
**Section 302 of the Sarbanes-Oxley Act of 2002**

I, Angela A. Minas, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three months ended March 31, 2012;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2012

/s/ Angela A. Minas
Angela A. Minas
Chief Financial Officer

**Exhibit 32.1**

**Certification of Chief Executive Officer**
**Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906**
**of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)**

The undersigned, the Chief Executive Officer of DCP Midstream GP, LLC, a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the three months ended March 31, 2012, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
May 10, 2012

*A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.*

**Exhibit 32.2**

**Certification of Chief Financial Officer**
**Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906**
**of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)**

The undersigned, the Chief Financial Officer of DCP Midstream GP, LLC, a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the three months ended March 31, 2012, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Angela A. Minas
Angela A. Minas
Chief Financial Officer
May 10, 2012

*A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.*