

DCP Midstream Partners, LP  
Form 10-Q  
August 06, 2013  
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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 June 30, 2013

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 03-0567133  
(State or other jurisdiction (I.R.S. Employer  
of incorporation or organization) Identification No.)

370 17th Street, Suite 2500 80202  
Denver, Colorado (Zip Code)  
(Address of principal executive offices)

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

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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 August 2, 2013, there were outstanding 78,201,309 common units representing limited partner interests.

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 FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2013  
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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
Btu	British thermal unit, a measurement of energy
Fractionation	the process by which natural gas liquids are separated into individual components
MMBtu	one million Btus
MMBtu/d	one million Btus per day
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

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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,” “should,” “intend,” “assume,” “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, 2012, or our 2012 Form 10-K, 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;
- volatility in the price of our common units;
- 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 contributions from affiliates, acquisitions, 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, 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;
  - 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 on budget and 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;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation, regulation of over-the-counter derivatives market and entities, and hydraulic fracturing regulations, or the increased regulation of our industry, and their impact on producers and customers served by our systems;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
  - the amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs;

industry changes, including the impact of consolidations, 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.

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)

	June 30, 2013 (Millions)	December 31, 2012
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$9	\$2
Accounts receivable:		
Trade, net of allowance for doubtful accounts of less than \$1 million	109	107
Affiliates	167	132
Inventories	36	76
Unrealized gains on derivative instruments	97	49
Other	2	2
Total current assets	420	368
Property, plant and equipment, net	2,679	2,550
Goodwill	154	154
Intangible assets, net	133	137
Investments in unconsolidated affiliates	384	304
Unrealized gains on derivative instruments	146	70
Other long-term assets	23	20
Total assets	\$3,939	\$3,603
<b>LIABILITIES AND EQUITY</b>		
Current liabilities:		
Accounts payable:		
Trade	\$277	\$151
Affiliates	24	72
Unrealized losses on derivative instruments	22	31
Capital spending accrual	19	44
Other	68	47
Total current liabilities	410	345
Long-term debt	1,740	1,620
Unrealized losses on derivative instruments	3	8
Other long-term liabilities	36	36
Total liabilities	2,189	2,009
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	357
Limited partners (78,201,309 and 61,346,058 common units issued and outstanding, respectively)	1,542	1,063
General partner	4	—
Accumulated other comprehensive loss	(13	) (15
Total partners' equity	1,533	1,405
Noncontrolling interests	217	189
Total equity	1,750	1,594

Total liabilities and equity	\$3,939	\$3,603
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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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	\$225	\$143	\$508	\$432
Sales of natural gas, propane, NGLs and condensate to affiliates	418	400	803	901
Transportation, processing and other	50	41	96	81
Transportation, processing and other to affiliates	11	9	28	21
Gains from commodity derivative activity, net	4	37	2	28
Gains from commodity derivative activity, net — affiliates	67	38	69	42
Total operating revenues	775	668	1,506	1,505
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	534	407	1,058	906
Purchases of natural gas, propane and NGLs from affiliates	39	83	101	280
Operating and maintenance expense	51	50	96	92
Depreciation and amortization expense	23	15	43	49
General and administrative expense	5	4	10	8
General and administrative expense — affiliates	11	13	22	28
Other expense	—	—	4	—
Total operating costs and expenses	663	572	1,334	1,363
Operating income	112	96	172	142
Interest expense	(14	) (11	) (26	) (24
Earnings from unconsolidated affiliates	8	2	16	8
Income before income taxes	106	87	162	126
Income tax expense	—	—	(1	) (1
Net income	106	87	161	125
Net income attributable to noncontrolling interests	(4	) (2	) (7	) (6
Net income attributable to partners	102	85	154	119
Net income attributable to predecessor operations	—	(6	) (6	) (20
General partner's interest in net income	(16	) (10	) (31	) (18
Net income allocable to limited partners	\$86	\$69	\$117	\$81
Net income per limited partner unit — basic and diluted	\$1.11	\$1.33	\$1.64	\$1.64
Weighted-average limited partner units outstanding — basic and diluted	77.3	51.9	71.3	49.4

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended		Six Months Ended		
	June 30,		June 30,		
	2013	2012	2013	2012	
	(Millions)				
Net income	\$ 106	\$ 87	\$ 161	\$ 125	
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	1	4	2	9	
Net unrealized losses on cash flow hedges	—	(2	) —	(2	)
Total other comprehensive income	1	2	2	7	
Total comprehensive income	107	89	163	132	
Total comprehensive income attributable to noncontrolling interests	(4	) (2	) (7	) (6	)
Total comprehensive income attributable to partners	\$ 103	\$ 87	\$ 156	\$ 126	
See accompanying notes to condensed consolidated financial statements.					

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

	Six Months Ended	
	June 30,	
	2013	2012
	(Millions)	
<b>OPERATING ACTIVITIES:</b>		
Net income	\$161	\$125
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	43	49
Earnings from unconsolidated affiliates	(16	) (8
Distributions from unconsolidated affiliates	22	8
Net unrealized gains on derivative instruments	(48	) (41
Other, net	6	—
Change in operating assets and liabilities, which (used) provided cash net of effects of acquisitions:		
Accounts receivable	(26	) 98
Inventories	39	15
Accounts payable	72	(204
Accrued interest	6	5
Other current assets and liabilities	12	5
Other long-term assets and liabilities	(1	) (5
Net cash provided by operating activities	270	47
<b>INVESTING ACTIVITIES:</b>		
Capital expenditures	(195	) (218
Acquisitions, net of cash acquired	—	(291
Acquisition of an additional interest in the Eagle Ford system and commodity hedge	(486	) —
Investments in unconsolidated affiliates	(87	) (42
Return of investment from unconsolidated affiliate	—	1
Net cash used in investing activities	(768	) (550
<b>FINANCING ACTIVITIES:</b>		
Proceeds from debt	1,079	1,008
Payments of debt	(960	) (807
Payment of deferred financing costs	(4	) (3
Excess purchase price over acquired interests and commodity hedges	(101	) —
Proceeds from issuance of common units, net of offering costs	563	248
Net change in advances to predecessor from DCP Midstream, LLC	32	102
Net change in advances to predecessor – noncontrolling interest	—	28
Distributions to limited partners and general partner	(123	) (79
Distributions to noncontrolling interests	(10	) (3
Contributions from noncontrolling interests	31	—
Distributions to DCP Midstream, LLC	(3	) —
Contributions from DCP Midstream, LLC	1	7
Net cash provided by financing activities	505	501
Net change in cash and cash equivalents	7	(2
Cash and cash equivalents, beginning of period	2	8
Cash and cash equivalents, end of period	\$9	\$6

See accompanying notes to condensed consolidated financial statements.

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

	Partners' Equity			Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	Predecessor Equity (Millions)	Limited Partners	General Partner			
Balance, January 1, 2013	\$357	\$ 1,063	\$—	\$ (15 )	\$ 189	\$1,594
Net income	6	117	31	—	7	161
Other comprehensive income	—	—	—	2	—	2
Net change in parent advances	32	—	—	—	—	32
Acquisition of an additional 46.67% interest in the Eagle Ford system	(395 )	—	—	—	—	(395 )
Issuance of units for the Eagle Ford system	—	125	—	—	—	125
Excess purchase price over carrying value of acquired investment of 33.33% interest in the Eagle Ford system and NGL hedge	—	(7 )	—	—	—	(7 )
Excess purchase price over carrying value of acquired additional 46.67% interest in the Eagle Ford system and commodity hedge	—	(219 )	—	—	—	(219 )
Issuance of 14,058,547 common units	—	561	—	—	—	561
Distributions to limited partners and general partner	—	(96 )	(27 )	—	—	(123 )
Distributions to noncontrolling interests	—	—	—	—	(10 )	(10 )
Contributions from noncontrolling interests	—	—	—	—	31	31
Contributions from DCP Midstream, LLC	—	1	—	—	—	1
Distributions to DCP Midstream, LLC	—	(3 )	—	—	—	(3 )
Balance, June 30, 2013	\$—	\$ 1,542	\$4	\$ (13 )	\$ 217	\$1,750

See accompanying notes to condensed consolidated financial statements.



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

	Partners' Equity			Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	Predecessor Equity (Millions)	Limited Partners	General Partner			
Balance, January 1, 2012	\$628	\$ 654	\$(5 )	\$ (21 )	\$ 306	\$1,562
Net income	20	81	18	—	6	125
Other comprehensive (loss) income	(1 )	—	—	8	—	7
Net change in parent advances	102	—	—	—	28	130
Acquisition of an additional 66.67% interest in Southeast Texas and NGL Hedge	(248 )	40	—	—	—	(208 )
Acquisition of an additional 49.9% interest in East Texas	—	—	—	—	(176 )	(176 )
Issuance of units for Southeast Texas	—	48	—	—	—	48
Issuance of units for East Texas	—	33	—	—	—	33
Deficit purchase price under carrying value of acquired net assets	—	57	—	(4 )	—	53
Issuance of 5,487,300 common units	—	248	—	—	—	248
Equity-based compensation	—	(1 )	—	—	—	(1 )
Distributions to limited partners and general partner	—	(64 )	(15 )	—	—	(79 )
Distributions to noncontrolling interests	—	—	—	—	(3 )	(3 )
Contributions from DCP Midstream, LLC	—	7	—	—	—	7
Balance, June 30, 2012	\$501	\$ 1,103	\$(2 )	\$ (17 )	\$ 161	\$1,746

See accompanying notes to condensed consolidated financial statements.

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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, our or the Partnership, is engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs and condensate; and transporting, storing and selling propane in wholesale markets.

We are a Delaware limited partnership that was formed in August 2005. Our partnership includes: our natural gas services segment (which includes our Northern Louisiana system; our Southern Oklahoma system; our 40% 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; our East Texas system; our Michigan system; our Southeast Texas system; our 80% interest in the Eagle Ford system, including the Goliad plant (of which 33.33% and 46.67% were acquired in November 2012 and March 2013, respectively) and our wholly-owned Eagle Plant), our NGL logistics segment (which includes the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, our 10% interest in the Texas Express intrastate NGL pipeline, the NGL storage facility in Michigan, the DJ Basin NGL fractionators and our minority ownership interests in the Mont Belvieu fractionators), and our wholesale propane logistics segment.

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. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Phillips 66 and 50% by Spectra Energy Corp, or Spectra Energy. 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 26% of us.

The condensed consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries where we have the ability to exercise control. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where 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 a 66.67% interest in Southeast Texas and commodity derivative hedge instruments related to the Southeast Texas storage business, which we acquired from DCP Midstream, LLC in March 2012, and an 80% interest in the Eagle Ford system, of which we acquired 33.33% and 46.67% in November 2012 and March 2013, respectively, from DCP Midstream, LLC. 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 the March 2012 transaction, we own 100% of Southeast Texas which we account for as a consolidated subsidiary. Prior to our acquisition of the additional 46.67% interest in the Eagle Ford system in March 2013, we accounted for our initial 33.33% interest as an unconsolidated affiliate using the equity method. Subsequent to the March 2013 transaction, we own 80% of the Eagle Ford system 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 condensed 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, and 80% interest in the Eagle Ford system 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 limited 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. In



addition, the results of operations for acquisitions accounted for as business combinations have been included in the condensed consolidated financial statements since their respective acquisition dates.

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.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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 note disclosures normally included in our annual financial statements prepared in accordance with GAAP have been condensed or omitted from these interim financial statements pursuant to such rules and regulations, although we believe that the disclosures made are adequate to make the information not misleading. Results of operations for the three and six months ended June 30, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013. These unaudited condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the 2012 audited consolidated financial statements and notes thereto included as Exhibit 99.3 in our Current Report on Form 8-K filed on June 14, 2013.

2. Acquisitions

On March 28, 2013, we acquired an additional 46.67% interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC and an \$87 million fixed price commodity derivative hedge for a three-year period for aggregate consideration of \$626 million, plus customary working capital and other purchase price adjustments. \$490 million of the consideration was financed with the net proceeds from our 3.875% 10-year Senior Notes offering, \$125 million was financed by the issuance at closing of an aggregate 2,789,739 of our common units to DCP Midstream, LLC and the remaining \$11 million was paid with cash on hand. The \$219 million excess purchase price over the carrying value of the acquired interest in the Eagle Ford system was recorded as a decrease in limited partners' equity. We also reimbursed DCP Midstream, LLC \$50 million for 46.67% of the capital spent to date by the Eagle Ford system for the construction of the Goliad plant, plus an incremental payment of \$23 million as reimbursement for 46.67% of preformation capital expenditures. Prior to the acquisition of the additional interest in the Eagle Ford system, we owned a 33.33% interest which we accounted for as an unconsolidated affiliate using the equity method. The Eagle Ford system acquisition represents a transaction between entities under common control and a change in reporting entity. Accordingly, our condensed consolidated financial statements have been adjusted to retrospectively include the historical results of our 80% interest in the Eagle Ford system for all periods presented, similar to the pooling method.

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

Historical Financial Information

The results of our 80% interest in the Eagle Ford system are included in the consolidated balance sheets as of December 31, 2012. The following table presents the previously reported December 31, 2012 consolidated balance sheet, adjusted for the acquisition of the additional 46.67% interest in the Eagle Ford system from DCP Midstream, LLC:

As of December 31, 2012

	DCP Midstream Partners, LP (As previously reported on Form 10-K filed on 2/27/13) (a)	Consolidate Eagle Ford system (b)	Remove Eagle Ford system Investment in Unconsolidated Affiliate (c)	Condensed Consolidated DCP Midstream Partners, LP (As currently reported on Form 8-K filed on 6/14/13)	
	(Millions)				
<b>ASSETS</b>					
Current assets:					
Cash and cash equivalents	\$1	\$1	\$—	\$2	
Accounts receivable	182	57	—	239	
Inventories	75	1	—	76	
Other	51	—	—	51	
Total current assets	309	59	—	368	
Property, plant and equipment, net	1,727	823	—	2,550	
Goodwill and intangible assets, net	291	—	—	291	
Investments in unconsolidated affiliates	558	1	(255	) 304	
Other non-current assets	87	3	—	90	
Total assets	\$2,972	\$886	\$(255	) \$3,603	
<b>LIABILITIES AND EQUITY</b>					
Accounts payable and other current liabilities	\$234	\$111	\$—	\$345	
Long-term debt	1,620	—	—	1,620	
Other long-term liabilities	35	9	—	44	
Total liabilities	1,889	120	—	2,009	
Commitments and contingent liabilities					
Equity:					
Partners' equity					
Net equity	1,063	612	(255	) 1,420	
Accumulated other comprehensive loss	(15	) —	—	(15	)
Total partners' equity	1,048	612	(255	) 1,405	
Noncontrolling interests	35	154	—	189	
Total equity	1,083	766	(255	) 1,594	
Total liabilities and equity	\$2,972	\$886	\$(255	) \$3,603	

(a)

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Amounts as previously reported with 33.33% of the Eagle Ford system presented within investments in unconsolidated affiliates.

- (b) Adjustments to present the Eagle Ford system on a consolidated basis with a 20% noncontrolling interest.
- (c) Adjustments to remove our 33.33% investment in unconsolidated affiliates.

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

The results of our 80% interest in the Eagle Ford system are included in the condensed consolidated statements of operations for the three and six months ended June 30, 2013 and 2012. The following tables present the previously reported condensed consolidated statements of operations for the three and six months ended June 30, 2012, adjusted for the acquisition of an 80% interest in the Eagle Ford system from DCP Midstream, LLC:

Three Months Ended June 30, 2012

	DCP Midstream Partners, LP (As previously reported on Form 10-Q filed on 8/8/12) (Millions)	Consolidate Eagle Ford system (a)	Condensed Consolidated DCP Midstream Partners, LP (As currently reported)	
Sales of natural gas, propane, NGLs and condensate	\$297	\$246	\$543	
Transportation, processing and other	42	8	50	
Gains from commodity derivative activity, net	75	—	75	
Total operating revenues	414	254	668	
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	274	216	490	
Operating and maintenance expense	30	20	50	
Depreciation and amortization expense	10	5	15	
General and administrative expense	11	6	17	
Total operating costs and expenses	325	247	572	
Operating income	89	7	96	
Interest expense	(11	) —	(11	)
Earnings from unconsolidated affiliates	2	—	2	
Income before income taxes	80	7	87	
Income tax expense	—	—	—	
Net income	80	7	87	
Net income attributable to noncontrolling interests	(1	) (1	) (2	)
Net income attributable to partners	\$79	\$6	\$85	

(a) Adjustments to present the Eagle Ford system on a consolidated basis with a 20% noncontrolling interest.

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

Six Months Ended June 30, 2012

	DCP Midstream Partners, LP (As previously reported on Form 10-Q filed on 8/8/12) (Millions)	Consolidate Eagle Ford system (a)	Condensed Consolidated DCP Midstream Partners, LP (As currently reported)	
Sales of natural gas, propane, NGLs and condensate	\$784	\$549	\$1,333	
Transportation, processing and other	85	17	102	
Gains from commodity derivative activity, net	70	—	70	
Total operating revenues	939	566	1,505	
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	706	480	1,186	
Operating and maintenance expense	56	36	92	
Depreciation and amortization expense	34	15	49	
General and administrative expense	22	14	36	
Total operating costs and expenses	818	545	1,363	
Operating income	121	21	142	
Interest expense	(24	) —	(24	)
Earnings from unconsolidated affiliates	8	—	8	
Income before income taxes	105	21	126	
Income tax expense	(1	) —	(1	)
Net income	104	21	125	
Net income attributable to noncontrolling interests	(2	) (4	) (6	)
Net income attributable to partners	\$102	\$17	\$119	

(a) Adjustments to present the Eagle Ford system on a consolidated basis with a 20% noncontrolling interest. The currently reported results are not intended to reflect actual results that would have occurred if the acquired business had been consolidated during the period presented.

### 3. Agreements and Transactions with Affiliates

#### DCP Midstream, LLC

##### Services Agreement and Other General and Administrative Charges

On February 14, 2013, we entered into a Services Agreement with DCP Midstream, LLC, which replaced the Omnibus Agreement, whereby DCP Midstream, LLC will continue to provide us with the general and administrative services previously provided under the Omnibus Agreement. The annual fee payable in future years to DCP Midstream, LLC under the Services Agreement will be consistent with the fee structure previously payable under the Omnibus Agreement, and will be \$29 million for 2013. The Services Agreement fee is subject to adjustment based on the scope of general and administrative services performed by DCP Midstream, LLC. Pursuant to the Services Agreement, we will reimburse DCP Midstream, LLC for expenses and expenditures incurred or payments made on our behalf.

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

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	Three Months Ended		Six Months Ended	
	June 30, 2013	2012	June 30, 2013	2012
Services/Omnibus Agreement	\$7	\$7	\$14	\$12
Other fees — DCP Midstream, LLC	4	6	8	16
Total — DCP Midstream, LLC	\$11	\$13	\$22	\$28

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## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

In addition to the fees paid pursuant to the Services Agreement and Omnibus Agreement, we incurred other general and administrative fees with DCP Midstream, LLC of \$1 million for the three and six months ended June 30, 2013 and less than \$1 million for the three and six months ended June 30, 2012. These amounts include allocated expenses, including professional services, insurance and internal audit. The Eagle Ford system incurred \$3 million and \$6 million in general and administrative expenses directly from DCP Midstream, LLC for the three months ended June 30, 2013 and 2012, respectively, and \$7 million and \$13 million in general and administrative expenses directly from DCP Midstream, LLC for the six months ended June 30, 2013 and 2012, respectively. For the six months ended June 30, 2012, Southeast Texas incurred \$3 million in general and administrative expenses directly from DCP Midstream, LLC, before the addition of Southeast Texas to the Omnibus Agreement in March 2012.

## Other Agreements and Transactions with DCP Midstream, LLC

In conjunction with our acquisitions of our East Texas and Southeast Texas systems, which are 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 and Southeast Texas capital projects. These reimbursements are for specific 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 less than \$1 million and \$2 million for the three months ended June 30, 2013 and 2012, respectively, and \$1 million and \$5 million for the six months ended June 30, 2013 and 2012, respectively. DCP Midstream, LLC made capital contributions to Southeast Texas for capital projects of \$2 million for both the three and six months ended June 30, 2012. We made a distribution to DCP Midstream, LLC related to capital projects at Southeast Texas of \$3 million for the six months ended June 30, 2013. DCP Midstream, LLC issued parental guarantees, totaling \$25 million as of June 30, 2013, in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We paid DCP Midstream, LLC a fee of 0.5% per annum on these outstanding guarantees. In August 2013, we terminated these guarantees with DCP Midstream, LLC.

## Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended June 30, 2013		Six Months Ended June 30, 2013	
	2013	2012	2013	2012
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	\$418	\$398	\$803	\$892
Transportation, processing and other	\$11	\$8	\$28	\$18
Purchases of natural gas, propane and NGLs	\$28	\$16	\$72	\$76
Gains from commodity derivative activity, net	\$67	\$38	\$69	\$42
General and administrative expense	\$11	\$13	\$22	\$28
ConocoPhillips (a):				
Sales of natural gas, propane, NGLs and condensate	\$—	\$2	\$—	\$9
Transportation, processing and other	\$—	\$1	\$—	\$3
Purchases of natural gas, propane and NGLs	\$—	\$18	\$—	\$67
Spectra Energy:				
Purchases of natural gas, propane and NGLs	\$11	\$49	\$29	\$135
Unconsolidated affiliates:				
Purchases of natural gas, propane and NGLs	\$—	\$—	\$—	\$2



(a) In connection with the Phillips 66 separation, ConocoPhillips is not considered to be a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

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

We had balances with affiliates as follows:

	June 30, 2013 (Millions)	December 31, 2012
DCP Midstream, LLC:		
Accounts receivable	\$167	\$132
Accounts payable	\$24	\$66
Unrealized gains on derivative instruments — current	\$96	\$48
Unrealized gains on derivative instruments — long-term	\$139	\$64
Unrealized losses on derivative instruments — current	\$6	\$11
Unrealized losses on derivative instruments — long-term	\$1	\$—
Spectra Energy:		
Accounts payable	\$—	\$5
Unconsolidated affiliates:		
Accounts payable	\$—	\$1

4. Inventories

Inventories were as follows:

	June 30, 2013 (Millions)	December 31, 2012
Natural gas	\$21	\$22
NGLs	15	54
Total inventories	\$36	\$76

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the condensed consolidated statements of operations. We recognized \$3 million lower of cost or market adjustments during the three and six months ended June 30, 2013, and \$14 million and \$19 million in lower of cost or market adjustments during the three and six months ended June 30, 2012, respectively.

5. Property, Plant and Equipment

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

	Depreciable Life	June 30, 2013 (Millions)	December 31, 2012
Gathering and transmission systems	20 — 50 Years	\$2,036	\$1,921
Processing, storage, and terminal facilities	35 — 60 Years	1,313	1,103
Other	3 — 30 Years	36	31
Construction work in progress		399	561
Property, plant and equipment		3,784	3,616
Accumulated depreciation		(1,105)	(1,066)
Property, plant and equipment, net		\$2,679	\$2,550

Interest capitalized on construction projects for the three months ended June 30, 2013 and 2012 was \$3 million and \$2 million, respectively, and for the six months ended June 30, 2013 and 2012 was \$5 million and \$3 million, respectively.



## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

We revised the depreciable lives for our gathering and transmission systems, processing, storage and terminal facilities, and other assets effective April 1, 2012. The key contributing factors to the change in depreciable lives is an increase in the producers' estimated remaining economically recoverable reserves resulting from the widespread application of techniques, such as hydraulic fracturing and horizontal drilling, that improve commodity production in the regions our assets serve. Advances in extraction processes, along with better technology used to locate commodity reserves, is giving producers greater access to unconventional commodities. Based on our property, plant and equipment as of April 1, 2012, the new remaining depreciable lives resulted in an approximate \$17 million reduction in depreciation expense for each of the three and six months ended June 30, 2012, which increased net income per limited partner unit by \$0.33 and \$0.34, respectively.

Depreciation expense was \$21 million and \$13 million for the three months ended June 30, 2013 and 2012, respectively, and \$39 million and \$45 million for the six months ended June 30, 2013 and 2012, respectively.

During the six months ended June 30, 2013, we discontinued certain construction projects and wrote off approximately \$4 million in construction work in progress to other expense in the condensed consolidated statements of operations.

## 6. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of	
		June 30, 2013 (Millions)	December 31, 2012
Discovery Producer Services LLC	40%	\$260	\$223
Texas Express Pipeline	10%	80	41
Mont Belvieu Enterprise Fractionator	12.5%	21	19
Mont Belvieu 1 Fractionator	20%	16	14
CrossPoint Pipeline, LLC	50%	6	6
Other	Various	1	1
Total investments in unconsolidated affiliates		\$384	\$304

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of \$29 million and \$30 million at June 30, 2013 and December 31, 2012, respectively, which is associated with, and is being amortized over, the life of the underlying long-lived assets of Discovery.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu 1 of \$5 million and \$6 million at June 30, 2013 and December 31, 2012, respectively, which is associated with, and is being amortized over the life of the underlying long-lived assets of Mont Belvieu 1.

There was an excess of the carrying amount of the investment over the underlying equity of the Texas Express Pipeline of \$2 million and less than \$1 million at June 30, 2013 and December 31, 2012, respectively, which is associated with interest capitalized during the construction of the pipeline and will be amortized over the life of the underlying long-lived assets of Texas Express Pipeline.

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended		Six Months Ended	
	June 30, 2013 (Millions)	2012	June 30, 2013	2012
Discovery Producer Services LLC	\$1	\$2	\$1	\$8
Mont Belvieu Enterprise Fractionator	2	—	6	—
Mont Belvieu 1 Fractionator	5	—	9	—

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Total earnings from unconsolidated affiliates	\$8	\$2	\$16	\$8
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## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

The following tables summarize the combined financial information of our investments in unconsolidated affiliates. The amounts included for the six months ended June 30, 2013 include corrected operating revenues, operating expenses and net income for the three months ended March 31, 2013 of \$108 million, \$67 million and \$41 million, respectively. This change has no impact to our earnings from unconsolidated affiliates in our condensed consolidated financial statements.

	Three Months Ended		Six Months Ended	
	June 30, 2013	2012	June 30, 2013	2012
(Millions)				
Statements of operations:				
Operating revenue	\$123	\$36	\$231	\$83
Operating expenses	\$72	\$32	\$139	\$66
Net income	\$51	\$4	\$92	\$16
			June 30, 2013	December 31, 2012
(Millions)				
Balance sheets:				
Current assets			\$152	\$129
Long-term assets			1,760	1,288
Current liabilities			(120	) (75
Long-term liabilities			(45	) (43
Net assets			\$1,747	\$1,299

## 7. 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.

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DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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 9 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.



DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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 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.

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

The following table presents the financial instruments carried at fair value as of June 30, 2013 and December 31, 2012, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	June 30, 2013			Total Carrying Value	December 31, 2012			Total Carrying Value
	Level 1	Level 2	Level 3		Level 1	Level 2	Level 3	
	(Millions)							
Current assets:								
Commodity derivatives (a)	\$—	\$10	\$87	\$97	\$—	\$9	\$40	\$49
Long-term assets:								
Commodity derivatives (b)	\$—	\$8	\$138	\$146	\$—	\$5	\$65	\$70
Current liabilities (c):								
Commodity derivatives	\$—	\$(18)	\$—	\$(18)	\$—	\$(26)	\$(1)	\$(27)
Interest rate derivatives	\$—	\$(4)	\$—	\$(4)	\$—	\$(4)	\$—	\$(4)
Long-term liabilities (d):								
Commodity derivatives	\$—	\$(3)	\$—	\$(3)	\$—	\$(6)	\$—	\$(6)
Interest rate derivatives	\$—	\$—	\$—	\$—	\$—	\$(2)	\$—	\$(2)

- (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

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 and six months ended June 30, 2013 and 2012, there were no transfers between Level 1 and Level 2 of the fair value hierarchy.

#### Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our 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 into/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.

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended June 30, 2013 (a):				
Beginning balance	\$61	\$122	\$—	\$—
Net realized and unrealized gains included in earnings (d)	45	16	—	—
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(19	) —	—	—
Ending balance	\$87	\$138	\$—	\$—
Net unrealized gains still held included in earnings (d)	\$41	\$16	\$—	\$—
Three months ended June 30, 2012 (b):				
Beginning balance	\$15	\$28	\$(3	) \$—
Net realized and unrealized gains included in earnings (d)	34	7	4	—
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(5	) —	(2	) —
Ending balance	\$44	\$35	\$(1	) \$—
Net unrealized gains still held included in earnings (d)	\$32	\$8	\$1	\$—

(a) There were no purchases, issuances and sales of derivatives for the three months ended June 30, 2013.

(b) There were no purchases, issuances and sales of derivatives for the three months ended June 30, 2012.

(c) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.

Represents the amount of total gains or losses for the period, included in gains or losses from commodity (d) derivative activity, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Six months ended June 30, 2013 (a):				
Beginning balance	\$40	\$65	\$(1	) \$—
Net realized and unrealized gains included in earnings (d)	46	11	—	—
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(23	) —	1	—
Purchases	24	62	—	—
Ending balance	\$87	\$138	\$—	\$—
Net unrealized gains still held included in earnings (d)	\$43	\$11	\$—	\$—
Six months ended June 30, 2012 (b):				
Beginning balance	\$1	\$1	\$(1	) \$—
Net realized and unrealized gains included in earnings (d)	31	7	1	—
Transfers into Level 3 (c)	—	—	—	—
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(1	) —	—	—
Purchases	\$13	\$27	\$(1	) \$—
Ending balance	\$44	\$35	\$(1	) \$—
Net unrealized gains still held included in earnings (d)	\$30	\$8	\$1	\$—

(a) There were no issuances and sales of derivatives for the six months ended June 30, 2013.

(b) There were no issuances and sales of derivatives for the six months ended June 30, 2012.

(c) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.

(d) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.

## 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 on our short or long position in contracts.

Product Group	June 30, 2013		
	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	\$214	\$0.24-\$1.97	Per gallon
Natural Gas	\$11	\$3.58-\$4.49	Per MMBtu

Liabilities

Natural Gas

less than \$1 million

\$3.80-\$4.32

Per MMBtu

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## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

## 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 NGL and crude oil swaps, and our NYMEX positions in natural gas. 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. Derivative instruments are carried at fair value. The carrying value of outstanding balances under our Credit Agreement is \$150 million as of June 30, 2013 and \$525 million as of December 31, 2012, which approximated fair value. The carrying and fair values of the 3.875% Senior Notes are \$494 million and \$469 million, respectively, as of June 30, 2013. The carrying and fair values of the 2.50% Senior Notes are \$497 million and \$493 million, respectively, as of June 30, 2013 and the carrying value was \$497 million as of December 31, 2012, which approximated fair value. The carrying and fair values of the 4.95% Senior Notes are \$349 million and \$358 million, respectively, as of June 30, 2013, and \$348 million and \$374 million, respectively, as of December 31, 2012. The carrying and fair values of the 3.25% Senior Notes are \$250 million and \$259 million, respectively, as of June 30, 2013, and \$250 million and \$259 million, respectively, as of December 31, 2012. We determine the fair value of our Credit Agreement 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 Senior Notes based on quotes obtained from bond dealers. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy.





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

## 8. Debt

Long-term debt was as follows:

	June 30, 2013 (Millions)	December 31, 2012
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 1.45% and 1.47%, respectively, due November 10, 2016 (a)	\$ 150	\$ 525
Debt Securities		
Issued March 14, 2013, interest at 3.875% payable semi-annually, due March 15, 2023	500	—
Issued November 27, 2012, interest at 2.50% payable semi-annually, due December 1, 2017	500	500
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350	350
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250	250
Unamortized discount	(10	) (5
Total long-term debt	\$1,740	\$1,620

\$150 million has been swapped to a fixed rate obligation with fixed rates ranging from 2.94% to 2.99%, for a net effective rate of 4.21% on the \$150 million of outstanding debt under our revolving credit facility as of June 30, (a)2013. \$150 million has been swapped to a fixed rate obligation with fixed rates ranging from 2.94% to 2.99%, for a net effective rate of 2.25% on the \$525 million of outstanding debt under our revolving credit facility as of December 31, 2012.

## Credit Agreement

We have a \$1 billion revolving credit facility that matures November 10, 2016, or the Credit Agreement.

At June 30, 2013 and December 31, 2012, we had \$1 million of letters of credit issued and outstanding under the Credit Agreement. As of June 30, 2013, the unused capacity under the Credit Agreement was \$849 million, of which approximately \$847 million was available for general working capital purposes.

Our borrowing capacity is limited at June 30, 2013 by the Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the November 10, 2016 maturity date.

## Debt Securities

On March 14, 2013, we issued \$500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of \$490 million, net of underwriters' fees, related expenses and unamortized discounts totaling \$10 million, which we used to fund a portion of the purchase price for the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes will be paid semi-annually on March 15 and September 15 of each year, commencing September 15, 2013. The notes will mature on March 15, 2023, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

The notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Credit Agreement. 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.



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

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

	Debt Maturities (Millions)
2014	\$—
2015	250
2016	150
2017	500
Thereafter	850
	1,750
Unamortized discount	(10 )
Total	\$1,740

#### 9. 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. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices; however, there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. The relationship of NGLs to crude oil continues to be lower than historical relationships; however, a significant amount of our NGL hedges from 2013 through 2016 are direct product hedges. 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 condensed 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, including fixed price sales. 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 propane distributor desires to

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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 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** — 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. During 2011, Southeast Texas commenced an expansion project to build an additional storage cavern. Upon completion of the expansion project in the second half of 2013, 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 the forecasted purchase of natural gas in the second half of 2013, Southeast Texas executed a series of derivative financial instruments, which have been designated as cash flow hedges. The balances in accumulated other comprehensive income, or AOCI, of these cash flow hedges were in a loss position of \$2 million as of June 30, 2013 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.

#### 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 June 30, 2013, we had interest rate swap agreements extending through June 2014 totaling \$150 million, which are designated as cash flow hedges. Based on our current operations, we believe our interest rate swap agreements

mitigate our interest rate risk associated with our variable-rate debt. At June 30, 2013, \$150 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 2.99%, and receive interest payments based on the one-month LIBOR.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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. 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.

On March 8, 2012, we settled \$195 million of our forward-starting interest rate swap agreements for \$7 million. The net deferred losses of \$5 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 June 30, 2013, 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 June 30, 2013, we had \$14 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 June 30, 2013, if a credit-risk related event were to occur we may be required to post additional collateral.

Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of June 30, 2013, 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 \$12 million.

As of June 30, 2013, we had \$150 million of individual interest rate swap instruments that were in a net liability position of \$4 million 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.

Unconsolidated Affiliates

Discovery Producer Services LLC, one of our unconsolidated affiliates, entered into agreements with a pipe vendor denominated in a foreign currency in connection with the expansion of 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.



## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

## Collateral

As of June 30, 2013, DCP Midstream, LLC had issued and outstanding parental guarantees totaling \$25 million in favor of certain counterparties to our commodity derivative instruments. These parental guarantees reduce the amount of cash we may be required to post as collateral. In August 2013, we terminated these guarantees with DCP Midstream, LLC. As of June 30, 2013, we had no cash collateral posted with counterparties to our commodity derivative instruments.

## Offsetting

Certain of our derivative instruments are subject to a master netting or similar arrangement, whereby we may elect to settle multiple positions with an individual counterparty through a single net payment. Each of our individual derivative instruments are presented on a gross basis on the condensed consolidated balance sheets, regardless of our ability to net settle our positions. Instruments that are governed by agreements that include net settle provisions allow final settlement, when presented with a termination event, of outstanding amounts by extinguishing the mutual debts owed between the parties in exchange for a net amount due. We have trade receivables and payables associated with derivative instruments, subject to master netting or similar agreements, which are not included in the table below. The following summarizes the gross and net amounts of our derivative instruments:

Description	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet June 30, 2013			Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet December 31, 2012		
		Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount		Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount
Assets:						
Commodity derivatives	\$243	\$ (9 )	\$234	\$119	\$ (10 )	\$109
Interest rate derivatives	\$—	\$—	\$—	\$—	\$—	\$—
Liabilities:						
Commodity derivatives	\$(21 )	\$9	\$(12 )	\$(33 )	\$10	\$(23 )
Interest rate derivatives	\$(4 )	\$—	\$(4 )	\$(6 )	\$—	\$(6 )

(a) There is no cash collateral pledged or received against these positions.

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

## Summarized Derivative Information

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

Balance Sheet Line Item	June 30, 2013	December 31, 2012	Balance Sheet Line Item	June 30, 2013	December 31, 2012
	(Millions)			(Millions)	
<b>Derivative Assets Designated as Hedging Instruments:</b>			<b>Derivative Liabilities Designated as Hedging Instruments:</b>		
Commodity derivatives:			Commodity derivatives:		
Unrealized gains on derivative instruments — current	\$—	\$—	Unrealized losses on derivative instruments — current	\$(2	) \$(3
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	\$—	\$—		\$(2	) \$(3
Interest rate derivatives:			Interest rate derivatives:		
Unrealized gains on derivative instruments — current	\$—	\$—	Unrealized losses on derivative instruments — current	\$(4	) \$(4
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	(2
	\$—	\$—		\$(4	) \$(6
<b>Derivative Assets Not Designated as Hedging Instruments:</b>			<b>Derivative Liabilities Not Designated as Hedging Instruments:</b>		
Commodity derivatives:			Commodity derivatives:		
Unrealized gains on derivative instruments — current	\$97	\$49	Unrealized losses on derivative instruments — current	\$(16	) \$(24
Unrealized gains on derivative instruments — long-term	146	70	Unrealized losses on derivative instruments — long-term	(3	) (6
	\$243	\$119		\$(19	) \$(30

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

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the three months ended June 30, 2013:

	Interest Rate Cash Flow Hedges (Millions)	Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
Net deferred losses in AOCI (beginning balance)	\$ (9 )	\$ (5 )	\$ —	\$ (14 )
Gains (losses) recognized in AOCI on derivatives — effective portion	—	—	—	—
Losses reclassified from AOCI to earnings — effective portion	1 (b)	—	—	1
Net deferred losses in AOCI (ending balance)	\$ (8 )	\$ (5 )	\$ —	\$ (13 )
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	\$ (4 )	\$ —	\$ —	\$ (4 )

(a) Relates to Discovery, our unconsolidated affiliate.

(b) Included in interest expense in our condensed consolidated statements of operations.

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the six months ended June 30, 2013:

	Interest Rate Cash Flow Hedges (Millions)	Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
Net deferred (losses) gains in AOCI (beginning balance)	\$ (10 )	\$ (6 )	\$ 1	\$ (15 )
Gains (losses) recognized in AOCI on derivatives — effective portion	—	1	(1 )	—
Losses reclassified from AOCI to earnings — effective portion	2 (b)	—	—	2
Net deferred losses in AOCI (ending balance)	\$ (8 )	\$ (5 )	\$ —	\$ (13 )
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	\$ (4 )	\$ —	\$ —	\$ (4 )

(a) Relates to Discovery, our unconsolidated affiliate.

(b) Included in interest expense in our condensed consolidated statements of operations.

For both the three and six months ended June 30, 2013, less than \$1 million of derivative losses attributable to the ineffective portion was recognized in gains or losses from commodity derivative activity, net and interest expense in our condensed consolidated statements of operations. For the three and six months ended June 30, 2013, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of amounts excluded from effectiveness testing or as a result of the discontinuance of cash flow hedges related to certain forecasted transactions

that are not probable of occurring.

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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 for the three months ended June 30, 2012:

	Losses Recognized in AOCI on Derivatives — Effective Portion	Losses Reclassified From AOCI to Earnings — Effective Portion	Losses Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing (c)
	(Millions)		
Interest rate derivatives	\$—	\$(4 ) (a)	\$—
Commodity derivatives	\$—	\$—	\$—
Foreign currency derivatives (b)	\$(2 )	\$—	\$—

(a) Included in interest expense in our condensed consolidated statements of operations.

(b) Relates to Discovery, our unconsolidated affiliate.

For the three months ended June 30, 2012, no derivative gains or losses were reclassified from AOCI to current (c) period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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 for the six months ended June 30, 2012:

	Losses Recognized in AOCI on Derivatives — Effective Portion	Losses Reclassified From AOCI to Earnings — Effective Portion	Losses Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing
	(Millions)		
Interest rate derivatives	\$—	\$(9 ) (a)	\$ (2 ) (a) (b)
Commodity derivatives	\$(1 )	\$—	\$ —
Foreign currency derivatives (c)	\$(1 )	\$—	\$ —

(a) Included in interest expense in our condensed consolidated statements of operations.

For the six months ended June 30, 2012, \$1 million of derivative losses were reclassified from AOCI to current (b) period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

(c) Relates to Discovery, our unconsolidated affiliate.

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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 June 30, 2013		Six Months Ended June 30, 2013	
	2012	2012	2012	2012
	(Millions)			
Third party:				
Realized (losses) gains	\$ (3 )	\$ (5 )	\$ (7 )	\$ 11 )
Unrealized gains	7	42	9	17
Gains from commodity derivative activity, net	\$ 4	\$ 37	\$ 2	\$ 28
Affiliates:				
Realized gains	\$ 16	\$ 15	\$ 30	\$ 17
Unrealized gains	51	23	39	25
Gains from commodity derivative activity, net —affiliates	\$ 67	\$ 38	\$ 69	\$ 42
Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended June 30, 2013		Six Months Ended June 30, 2013	
	2012	2012	2012	2012
	(Millions)			
Third party:				
Realized losses	\$ (1 )	\$ (3 )	\$ (1 )	\$ (6 )
Unrealized gains	1	3	1	6
Interest expense	\$ —	\$ —	\$ —	\$ —

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.

Year of Expiration	June 30, 2013			
	Crude Oil Net (Short) Position (Bbls)	Natural Gas Net (Short) Position (MMBtu)	Natural Gas Liquids Net (Short) Position (Bbls)	Natural Gas Basis Swaps Net (Short) Long Position (MMBtu)
2013	(497,756 )	(10,822,652 )	(2,407,256 )	(460,000 )
2014	(636,195 )	(10,358,620 )	(5,231,910 )	8,940,000
2015	(453,695 )	(10,371,475 )	(5,691,570 )	3,650,000
2016	(195,922 )	(1,838,564 )	(813,267 )	—
Year of Expiration	June 30, 2012			
	Crude Oil Net (Short) Position	Natural Gas Net (Short) Position	Natural Gas Liquids Net (Short) Position	Natural Gas Basis Swaps Net Long (Short)

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	(Bbls)	(MMBtu)	(Bbls)	position (Mmbtu)
2012	(351,493	) (5,702,500	) (1,224,358	) 3,645,000
2013	(932,504	) (2,865,000	) (700,975	) 6,472,500
2014	(547,500	) (365,000	) (629,625	) (900,000 )
2015	(365,000	) —	(155,250	) —
2016	(183,000	) —	—	—

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## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of June 30, 2013, we have swaps with a notional value of \$70 million and \$80 million, which, in aggregate, exchange \$150 million of our floating rate obligation to a fixed rate obligation through June 2014.

## 10. 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 in the partnership agreement, to unitholders of record on the applicable record date, as determined by our general partner.

On June 14, 2013, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of \$300 million, which became effective on June 27, 2013. The shelf registration statement will allow us to issue additional common units under an equity distribution agreement. As of June 30, 2013, we have issued no securities under this registration statement.

In March 2013, we issued 2,789,739 common units to DCP Midstream, LLC as partial consideration for 46.67% interest in the Eagle Ford system.

In March 2013, we issued 12,650,000 common units at \$40.63 per unit. We received proceeds of \$494 million, net of offering costs.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, of common units having an aggregate offering amount of up to \$150 million. During the three and six months ended June 30, 2013, we issued 1,408,547 of our common units pursuant to the equity distribution agreement and received proceeds of \$67 million, net of commissions and accrued offering costs of \$2 million, which were used to finance growth opportunities and for general corporate purposes. As of June 30, 2013, no common units remain available for sale pursuant to this equity distribution agreement.

The following table presents our cash distributions paid in 2013 and 2012:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
May 15, 2013	\$0.70	\$69
February 14, 2013	\$0.69	\$54
November 14, 2012	\$0.68	\$53
August 14, 2012	\$0.67	\$49
May 15, 2012	\$0.66	\$43
February 14, 2012	\$0.65	\$37

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

Basic and diluted net income or loss per limited partner unit is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding limited partner units during the period. Diluted net income or loss 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 20,370 and 28,510 equivalent units during the three months ended June 30, 2013 and 2012, respectively, and 22,751 and 40,681 equivalent units during the six months ended June 30, 2013 and 2012, respectively.



DCP MIDSTREAM PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

12. 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 (“Marysville”) on December 30, 2010 (the “Acquisition”). The Claim involves actions taken and time periods prior to our ownership of EE Group and Marysville, and includes several causes of action including claims of civil conspiracy, breach of fiduciary duty and fraud. We acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and a 100% interest in EE Group, which owned the remaining 5% interest in Marysville. The Claimants seek, 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. In August 2012, we entered into a Settlement Agreement with the Claimants in which the Claimants have agreed that if an award is issued to the Claimants in the arbitration, the Claimants will not attempt to recover such an award from us. Additionally, in November 2012, we entered into a Settlement Agreement with the prior owners of EE Group in which such prior owners, who are named Respondents in the arbitration, agreed to fully release us from any liability that may arise out of the arbitration. Notwithstanding those settlement agreements, this matter 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.

**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.

**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 incorporates 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.

13. Business Segments

Our operations are located in the United States and are organized into three reporting segments: Natural Gas Services; NGL Logistics; and 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, our 40% interest in Discovery, our 80% interest in the Eagle Ford system, and our wholly-owned Eagle Plant.

**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, our 10% interest in the Texas Express NGL pipeline, the NGL storage facility in Michigan, the DJ Basin NGL fractionators in Colorado, our 12.5% interest in the Mont Belvieu Enterprise fractionator, and our 20% interest in the Mont Belvieu 1 fractionator.

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 distributors. The segment consists of six owned rail terminals, one owned marine terminal, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

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.

The following tables set forth our segment information:

Three Months Ended June 30, 2013

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	\$703	\$19	\$53	\$—	\$775
Total purchases	(525 )	—	(48 )	—	(573 )
Gross margin (a)	\$178	\$19	\$5	—	\$202
Operating and maintenance expense	(43 )	(4 )	(4 )	—	(51 )
Depreciation and amortization expense	(21 )	(2 )	—	—	(23 )
General and administrative expense	—	—	—	(16 )	(16 )
Other expense	—	—	—	—	—
Earnings from unconsolidated affiliates	1	7	—	—	8
Interest expense	—	—	—	(14 )	(14 )
Income tax expense	—	—	—	—	—
Net income (loss)	115	20	1	(30 )	106
Net income attributable to noncontrolling interests	(4 )	—	—	—	(4 )
Net income (loss) attributable to partners	\$111	\$20	\$1	\$(30 )	\$102
Non-cash derivative mark-to-market (b)	\$58	\$—	\$—	\$—	\$58
Non-cash lower of cost or market adjustments	\$2	\$—	\$1	\$—	\$3

Three Months Ended June 30, 2012

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	\$580	\$15	\$73	\$—	\$668
Total purchases	(418 )	—	(72 )	—	(490 )
Gross margin (a)	\$162	\$15	\$1	\$—	\$178
Operating and maintenance expense	(42 )	(4 )	(4 )	—	(50 )
Depreciation and amortization expense	(14 )	(1 )	—	—	(15 )
General and administrative expense	—	—	—	(17 )	(17 )
Earnings from unconsolidated affiliates	2	—	—	—	2
Interest expense	—	—	—	(11 )	(11 )
Net income (loss)	108	10	(3 )	(28 )	87
Net income attributable to noncontrolling interests	(2 )	—	—	—	(2 )
Net income (loss) attributable to partners	\$106	\$10	\$(3 )	\$(28 )	\$85
Non-cash derivative mark-to-market (b)	\$49	\$—	\$16	\$—	\$65

Non-cash lower of cost or market adjustments	\$—	\$—	\$14	\$—	\$14
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DCP MIDSTREAM PARTNERS, LP  
 NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)  
 (Unaudited)

Six Months Ended June 30, 2013

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total	
	(Millions)					
Total operating revenue	\$1,260	\$38	\$208	\$—	\$1,506	
Total purchases	(984	) —	(175	) —	(1,159	)
Gross margin (a)	\$276	\$38	\$33	—	\$347	
Operating and maintenance expense	(81	) (8	) (7	) —	(96	)
Depreciation and amortization expense	(39	) (3	) (1	) —	(43	)
General and administrative expense	—	—	—	(32	) (32	)
Other expense	—	—	(4	) —	(4	)
Earnings from unconsolidated affiliates	1	15	—	—	16	
Interest expense	—	—	—	(26	) (26	)
Income tax expense	—	—	—	(1	) (1	)
Net income (loss)	157	42	21	(59	) 161	
Net income attributable to noncontrolling interests	(7	) —	—	—	(7	)
Net income (loss) attributable to partners	\$150	\$42	\$21	\$(59)	\$154	
Non-cash derivative mark-to-market (b)	\$49	\$—	\$(1)	) \$—	\$48	
Non-cash lower of cost or market adjustments	\$2	\$—	\$1	\$—	\$3	
Capital expenditures	\$190	\$4	\$1	\$—	\$195	
Acquisition expenditures	\$486	\$—	\$—	\$—	\$486	
Investments in unconsolidated affiliates	\$44	\$43	\$—	\$—	\$87	

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

Six Months Ended June 30, 2012

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	\$1,197	\$31	\$277	\$—	\$1,505
Total purchases	(931 )	—	(255 )	—	(1,186 )
Gross margin (a)	\$266	\$31	\$22	\$—	\$319
Operating and maintenance expense	(77 )	(8 )	(7 )	—	(92 )
Depreciation and amortization expense	(45 )	(3 )	(1 )	—	(49 )
General and administrative expense	—	—	—	(36 )	(36 )
Other income	—	—	—	—	—
Earnings from unconsolidated affiliates	8	—	—	—	8
Interest expense	—	—	—	(24 )	(24 )
Income tax expense	—	—	—	(1 )	(1 )
Net income (loss)	152	20	14	(61 )	125
Net income attributable to noncontrolling interests	(6 )	—	—	—	(6 )
Net income (loss) attributable to partners	\$146	\$20	\$14	\$(61 )	\$119
Non-cash derivative mark-to-market (b)	\$26	\$—	\$16	\$(1 )	\$41
Non-cash lower of cost or market adjustments	\$4	\$—	\$15	\$—	\$19
Capital expenditures	\$213	\$3	\$2	\$—	\$218
Acquisition expenditures	\$291	\$—	\$—	\$—	\$291
Investments in unconsolidated affiliates	\$31	\$11	\$—	\$—	\$42

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

	June 30, 2013 (Millions)	December 31, 2012
Segment long-term assets:		
Natural Gas Services (c)	\$2,863	\$2,706
NGL Logistics	388	340
Wholesale Propane Logistics	102	105
Other (d)	166	84
Total long-term assets	3,519	3,235
Current assets (c)	420	368
Total assets	\$3,939	\$3,603

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

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

The segment information for the three and six months ended June 30, 2013 and 2012, and as of December 31, 2012, includes the results of our 80% interest in the Eagle Ford system, and the segment information for the six months ended June 30, 2012, includes the results of our 100% interest in Southeast Texas, transfers of net assets

(c) 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.

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

## 14. Supplemental Cash Flow Information

	Six Months Ended June 30, 2013 (Millions)	2012
Cash paid for interest and income taxes:		
Cash paid for interest, net of amounts capitalized	\$17	\$6
Cash paid for income taxes, net of income tax refunds	\$1	\$1
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	\$28	\$37
Other non-cash additions of property, plant and equipment	\$1	\$7
Accounts payable related to equity issuance costs	\$2	\$—

## 15. 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 June 14, 2012, 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.



## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

Condensed Consolidating Balance Sheet						
June 30, 2013						
	Parent	Subsidiary	Non-Guarantor	Consolidating	Consolidated	
	Guarantor	Issuer	Subsidiaries	Adjustments		
	(Millions)					
<b>ASSETS</b>						
Current assets:						
Cash and cash equivalents	\$—	\$8	\$ 2	\$(1	) \$9	
Accounts receivable, net	—	—	276	—	276	
Inventories	—	—	36	—	36	
Other	—	—	99	—	99	
Total current assets	—	8	413	(1	) 420	
Property, plant and equipment, net	—	—	2,679	—	2,679	
Goodwill and intangible assets, net	—	—	287	—	287	
Advances receivable — consolidated subsidiaries	1,440	1,515	—	(2,955	) —	
Investments in consolidated subsidiaries	95	316	—	(411	) —	
Investments in unconsolidated affiliates	—	—	384	—	384	
Other long-term assets	—	13	156	—	169	
Total assets	\$1,535	\$1,852	\$ 3,919	\$(3,367	) \$3,939	
<b>LIABILITIES AND EQUITY</b>						
Accounts payable and other current liabilities	\$2	\$17	\$ 392	\$(1	) \$410	
Advances payable — consolidated subsidiaries	—	—	2,955	(2,955	) —	
Long-term debt	—	1,740	—	—	1,740	
Other long-term liabilities	—	—	39	—	39	
Total liabilities	2	1,757	3,386	(2,956	) 2,189	
Commitments and contingent liabilities						
Equity:						
Partners' equity:						
Net equity	1,533	103	321	(411	) 1,546	
Accumulated other comprehensive loss	—	(8	) (5	) —	(13	)
Total partners' equity	1,533	95	316	(411	) 1,533	
Noncontrolling interests	—	—	217	—	217	
Total equity	1,533	95	533	(411	) 1,750	
Total liabilities and equity	\$1,535	\$1,852	\$ 3,919	\$(3,367	) \$3,939	

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

Condensed Consolidating Balance Sheet					
December 31, 2012 (a)					
	Parent	Subsidiary	Non-Guarantor	Consolidating	Consolidated
	Guarantor	Issuer	Subsidiaries	Adjustments	
	(Millions)				
<b>ASSETS</b>					
Current assets:					
Cash and cash equivalents	\$—	\$3	\$ 2	\$(3)	) \$2
Accounts receivable, net	—	—	239	—	239
Inventories	—	—	76	—	76
Other	—	—	51	—	51
Total current assets	—	3	368	(3)	) 368
Property, plant and equipment, net	—	—	2,550	—	2,550
Goodwill and intangible assets, net	—	—	291	—	291
Advances receivable — consolidated subsidiaries	873	1,424	—	(2,297)	) —
Investments in consolidated subsidiaries	532	728	—	(1,260)	) —
Investments in unconsolidated affiliates	—	—	304	—	304
Other long-term assets	—	11	79	—	90
Total assets	\$1,405	\$2,166	\$ 3,592	\$(3,560)	) \$3,603
<b>LIABILITIES AND EQUITY</b>					
Accounts payable and other current liabilities	\$—	\$12	\$ 336	\$(3)	) \$345
Advances payable — consolidated subsidiaries	—	—	2,297	(2,297)	) —
Long-term debt	—	1,620	—	—	1,620
Other long-term liabilities	—	2	42	—	44
Total liabilities	—	1,634	2,675	(2,300)	) 2,009
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Predecessor equity	—	—	357	—	357
Net equity	1,405	542	376	(1,260)	) 1,063
Accumulated other comprehensive loss	—	(10)	) (5)	) —	(15)
Total partners' equity	1,405	532	728	(1,260)	) 1,405
Noncontrolling interests	—	—	189	—	189
Total equity	1,405	532	917	(1,260)	) 1,594
Total liabilities and equity	\$1,405	\$2,166	\$ 3,592	\$(3,560)	) \$3,603

The financial information as of December 31, 2012 includes the results of our 80% interest in the Eagle Ford system, a transfer of net assets between entities under common control that was accounted for as if the transfer (a) 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 Statement of Operations  
Three Months Ended June 30, 2013

	Parent Guarantor	Subsidiary Issuer	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated	
	(Millions)					
Operating revenues:						
Sales of natural gas, propane, NGLs and condensate	\$—	\$—	\$643	\$—	\$643	
Transportation, processing and other	—	—	61	—	61	
Gains (losses) from commodity derivative activity, net	—	—	71	—	71	
Total operating revenues	—	—	775	—	775	
Operating costs and expenses:						
Purchases of natural gas, propane and NGLs	—	—	573	—	573	
Operating and maintenance expense	—	—	51	—	51	
Depreciation and amortization expense	—	—	23	—	23	
General and administrative expense	—	—	16	—	16	
Total operating costs and expenses	—	—	663	—	663	
Operating income	—	—	112	—	112	
Interest expense, net	—	(14	) —	—	(14	)
Income from consolidated subsidiaries	102	116	—	(218	) —	
Earnings from unconsolidated affiliates	—	—	8	—	8	
Income before income taxes	102	102	120	(218	) 106	
Income tax expense	—	—	—	—	—	
Net income	102	102	120	(218	) 106	
Net income attributable to noncontrolling interests	—	—	(4	) —	(4	)
Net income attributable to partners	\$102	\$102	\$116	\$(218	) \$102	

Condensed Consolidating Statement of Comprehensive Income  
Three Months Ended June 30, 2013

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated	
	(Millions)					
Net income	\$102	\$102	\$120	\$(218	) \$106	
Other comprehensive income:						
Reclassification of cash flow hedge losses into earnings		1			1	
Other comprehensive income from consolidated subsidiaries	1	—	—	(1	) —	
Total other comprehensive income	1	1	—	(1	) 1	
Total comprehensive income	103	103	120	(219	) 107	
Total comprehensive income attributable to noncontrolling interests			(4	)	(4	)

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Total comprehensive income attributable to partners	\$ 103	\$ 103	\$ 116	\$(219	) \$103
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## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

	Condensed Consolidating Statement of Operations					
	Three Months Ended June 30, 2012 (a)					
	Parent	Subsidiary	Non-Guarantor	Consolidating	Consolidated	
	Guarantor	Issuer	Subsidiaries	Adjustments		
	(Millions)					
Operating revenues:						
Sales of natural gas, propane, NGLs and condensate	\$—	\$—	\$ 543	\$—	\$543	
Transportation, processing and other	—	—	50	—	50	
Losses from commodity derivative activity, net	—	—	75	—	75	
Total operating revenues	—	—	668	—	668	
Operating costs and expenses:						
Purchases of natural gas, propane and NGLs	—	—	490	—	490	
Operating and maintenance expense	—	—	50	—	50	
Depreciation and amortization expense	—	—	15	—	15	
General and administrative expense	—	—	17	—	17	
Total operating costs and expenses	—	—	572	—	572	
Operating income	—	—	96	—	96	
Interest expense, net	—	(10	) (1	) —	(11	)
Income from consolidated subsidiaries	85	95	—	(180	) —	
Earnings from unconsolidated affiliates	—	—	2	—	2	
Income before income taxes	85	85	97	(180	) 87	
Income tax expense	—	—	—	—	—	
Net income	85	85	97	(180	) 87	
Net loss attributable to noncontrolling interests	—	—	(2	) —	(2	)
Net income attributable to partners	\$85	\$85	\$ 95	\$(180	) \$85	

The financial information for the three months ended June 30, 2012 includes the results of our 80% interest in the Eagle Ford system, 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 Statement of Comprehensive Income				
	Three Months Ended June 30, 2012 (a)				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income	\$85	\$85	\$ 97	\$(180 )	\$87
Other comprehensive loss:					
Reclassification of cash flow hedge losses into earnings	—	4	—	—	4
Net unrealized losses on cash flow hedges	—	(1 )	(1 )	—	(2 )
Other comprehensive loss from consolidated subsidiaries	2	(1 )	—	(1 )	—
Total other comprehensive loss	2	2	(1 )	(1 )	2
Total comprehensive income	87	87	96	(181 )	89
Total comprehensive loss attributable to noncontrolling interests	—	—	(2 )	—	(2 )
Total comprehensive income attributable to partners	\$87	\$87	\$ 94	\$(181 )	\$87

The financial information for the three months ended June 30, 2012 includes the results of our 80% interest in the Eagle Ford system, 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 Statement of Operations  
Six Months Ended June 30, 2013

	Parent Guarantor	Subsidiary Issuer	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated	
	(Millions)					
Operating revenues:						
Sales of natural gas, propane, NGLs and condensate	\$—	\$—	\$1,311	\$—	\$1,311	
Transportation, processing and other	—	—	124	—	124	
Gains (losses) from commodity derivative activity, net	—	—	71	—	71	
Total operating revenues	—	—	1,506	—	1,506	
Operating costs and expenses:						
Purchases of natural gas, propane and NGLs	—	—	1,159	—	1,159	
Operating and maintenance expense	—	—	96	—	96	
Depreciation and amortization expense	—	—	43	—	43	
General and administrative expense	—	—	32	—	32	
Other expense	—	—	4	—	4	
Total operating costs and expenses	—	—	1,334	—	1,334	
Operating income	—	—	172	—	172	
Interest expense, net	—	(26	) —	—	(26	)
Income from consolidated subsidiaries	154	180	—	(334	) —	
Earnings from unconsolidated affiliates	—	—	16	—	16	
Income before income taxes	154	154	188	(334	) 162	
Income tax expense	—	—	(1	) —	(1	)
Net income	154	154	187	(334	) 161	
Net income attributable to noncontrolling interests	—	—	(7	) —	(7	)
Net income attributable to partners	\$154	\$154	\$180	\$(334	) \$154	

Condensed Consolidating Statement of Comprehensive Income  
Six Months Ended June 30, 2013

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated	
	(Millions)					
Net income	\$154	\$154	\$187	\$(334	) \$161	
Other comprehensive income:						
Reclassification of cash flow hedge losses into earnings	—	2	—	—	2	
Other comprehensive income from consolidated subsidiaries	2	—	—	(2	) —	
Total other comprehensive income	2	2	—	(2	) 2	
Total comprehensive income	156	156	187	(336	) 163	
	—	—	(7	) —	(7	)

Total comprehensive income attributable  
to noncontrolling interests

Total comprehensive income attributable to partners	\$ 156	\$ 156	\$ 180	\$(336	) \$ 156
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## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

	Condensed Consolidating Statement of Operations					
	Six Months Ended June 30, 2012 (a)					
	Parent	Subsidiary	Non-Guarantor	Consolidating	Consolidated	
	Guarantor	Issuer	Subsidiaries	Adjustments		
	(Millions)					
Operating revenues:						
Sales of natural gas, propane, NGLs and condensate	\$—	\$—	\$ 1,333	\$—	\$1,333	
Transportation, processing and other	—	—	102	—	102	
Losses from commodity derivative activity, net	—	—	70	—	70	
Total operating revenues	—	—	1,505	—	1,505	
Operating costs and expenses:						
Purchases of natural gas, propane and NGLs	—	—	1,186	—	1,186	
Operating and maintenance expense	—	—	92	—	92	
Depreciation and amortization expense	—	—	49	—	49	
General and administrative expense	—	—	36	—	36	
Total operating costs and expenses	—	—	1,363	—	1,363	
Operating income	—	—	142	—	142	
Interest expense, net	—	(23	) (1	) —	(24	)
Income from consolidated subsidiaries	119	142	—	(261	) —	
Earnings from unconsolidated affiliates	—	—	8	—	8	
Income before income taxes	119	119	149	(261	) 126	
Income tax expense	—	—	(1	) —	(1	)
Net income	119	119	148	(261	) 125	
Net loss attributable to noncontrolling interests	—	—	(6	) —	(6	)
Net income attributable to partners	\$119	\$119	\$ 142	\$(261	) \$119	

The financial information for the six months ended June 30, 2012 includes the results of our 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas, transfers of net assets between entities under (a) 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 Statement of Comprehensive Income Six Months Ended June 30, 2012 (a)				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income	\$ 119	\$ 119	\$ 148	\$(261 )	\$ 125
Other comprehensive loss:					
Reclassification of cash flow hedge losses into earnings	—	9	—	—	9
Net unrealized losses on cash flow hedges	—	—	(2 )	—	(2 )
Other comprehensive loss from consolidated subsidiaries	7	(2 )	—	(5 )	—
Total other comprehensive loss	7	7	(2 )	(5 )	7
Total comprehensive income	126	126	146	(266 )	132
Total comprehensive loss attributable to noncontrolling interests	—	—	(6 )	—	(6 )
Total comprehensive income attributable to partners	\$ 126	\$ 126	\$ 140	\$(266 )	\$ 126

(a) The financial information for the six months ended June 30, 2012 includes the results of our 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas, 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.

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

	Condensed Consolidating Statement of Cash Flows				
	Six Months Ended June 30, 2013				
	Parent	Subsidiary	Non-Guarantor	Consolidating	Consolidated
	Guarantor	Issuer	Subsidiaries	Adjustments	
	(Millions)				
<b>OPERATING ACTIVITIES</b>					
Net cash (used in) provided by operating activities	\$(440	) \$(110	) \$ 818	\$ 2	\$ 270
<b>INVESTING ACTIVITIES:</b>					
Capital expenditures	—	—	(195	) —	(195 )
Acquisition of an additional interest and commodity hedge	—	—	(486	) —	(486 )
Investments in unconsolidated affiliates	—	—	(87	) —	(87 )
Net cash used in investing activities	—	—	(768	) —	(768 )
<b>FINANCING ACTIVITIES:</b>					
Proceeds from debt	—	1,079	—	—	1,079
Payments of debt	—	(960	) —	—	(960 )
Payments of deferred financing cost	—	(4	) —	—	(4 )
Excess purchase price over acquired net assets and commodity hedge	—	—	(101	) —	(101 )
Proceeds from issuance of common units, net of offering cost	563	—	—	—	563
Net change in advances to predecessor from DCP Midstream, LLC	—	—	32	—	32
Distributions to limited partners and general partner	(123	) —	—	—	(123 )
Distributions to noncontrolling interests	—	—	(10	) —	(10 )
Contributions from noncontrolling interests	—	—	31	—	31
Distributions to DCP Midstream, LLC	—	—	(3	) —	(3 )
Contributions from DCP Midstream, LLC	—	—	1	—	1
Net cash provided by (used in) financing activities	440	115	(50	) —	505
Net change in cash and cash equivalents	—	5	—	2	7
Cash and cash equivalents, beginning of period	—	3	2	(3	) 2
Cash and cash equivalents, end of period	\$—	\$ 8	\$ 2	\$(1	) \$ 9

## DCP MIDSTREAM PARTNERS, LP

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

	Condensed Consolidating Statements of Cash Flows				
	Six Months Ended June 30, 2012 (a)				
	Parent	Subsidiary	Non-Guarantor	Consolidating	Consolidated
	Guarantor	Issuer	Subsidiaries	Adjustments	
	(Millions)				
<b>OPERATING ACTIVITIES</b>					
Net cash (used in) provided by operating activities	\$ (169	) \$ (194	) \$ 413	\$ (3	) \$ 47
<b>INVESTING ACTIVITIES:</b>					
Capital expenditures	—	—	(218	) —	(218
Acquisitions, net of cash acquired	—	—	(291	) —	(291
Investments in unconsolidated affiliates	—	—	(42	) —	(42
Return of investment in unconsolidated affiliates	—	—	1	—	1
Net cash used in investing activities	—	—	(550	) —	(550
<b>FINANCING ACTIVITIES:</b>					
Proceeds from debt	—	1,008	—	—	1,008
Payments of debt	—	(807	) —	—	(807
Payment of deferred financing costs	—	(3	) —	—	(3
Proceeds from issuance of common units, net of offering costs	248	—	—	—	248
Distributions to limited partners and general partner	(79	) —	—	—	(79
Distributions to noncontrolling interests	—	—	(3	) —	(3
Contributions from DCP Midstream, LLC	—	—	7	—	7
Net change in advances to predecessor from DCP Midstream, LLC	—	—	102	—	102
Net change in advances to predecessor - noncontrolling interest	—	—	28	—	28
Net cash provided by (used in) financing activities	169	198	134	—	501
Net change in cash and cash equivalents	—	4	(3	) (3	) (2
Cash and cash equivalents, beginning of period	—	4	6	(2	) 8
Cash and cash equivalents, end of period	\$ —	\$ 8	\$ 3	\$ (5	) \$ 6

The financial information during the six months ended June 30, 2012 includes the results of our 80% interest in the Eagle Ford system and our 100% interest in Southeast Texas, transfers of net assets between entities under (a) 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)

16. Subsequent Events

On July 25, 2013, we announced that the board of directors of the General Partner declared a quarterly distribution of \$0.71 per unit, payable on August 14, 2013 to unitholders of record on August 7, 2013.

On August 5, 2013, we completed the acquisition of DCP LaSalle Plant, LLC, or LaSalle, from DCP Midstream, LLC for aggregate consideration of \$209 million, subject to certain purchase price adjustments. LaSalle is a 110 MMcf/d natural gas processing plant currently under construction with plans to expand to a 160 MMcf/d. We also entered into a 15-year fee-based agreement with an affiliate of DCP Midstream, LLC, which provides us with a fixed demand charge. The fee-based agreement also provides us with a throughput fee on all volumes processed at LaSalle. The processing agreement commences with commercial operations of the new plant, which is expected to be in-service in the second half of 2013. The transaction was financed at closing from borrowings under our revolving credit facility. The contribution of LaSalle represents a transfer of assets between entities under common control. We will include the results of LaSalle prospectively from the date of contribution in our Natural Gas Services segment.

On August 5, 2013, we also completed the acquisition of Front Range, LLC, or Front Range, from DCP Midstream, LLC for aggregate consideration of \$86 million, subject to certain purchase price adjustments. Front Range owns a 33.33% equity method interest in Front Range Pipeline LLC, a joint venture with affiliates of Enterprise Products Partners L.P. and Anadarko Petroleum Corporation, which was formed to construct a new NGL pipeline that will originate in the DJ Basin and extend approximately 435 miles to Skellytown, Texas. The pipeline operator expects the NGL pipeline to be mechanically complete in the fourth quarter of 2013. The transaction was financed at closing from borrowings under our revolving credit facility. The contribution of Front Range represents a transfer of assets between entities under common control. We will include the results of Front Range prospectively from the date of contribution in our NGL Logistics segment.

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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 as Exhibit 99.3 in our Current Report on Form 8-K filed with the SEC on June 14, 2013.

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.

Our business is impacted by commodity prices, which we mitigate on an overall Partnership basis through a multi-year hedging program, as well as volumes of throughput and sales of natural gas and NGLs. Various factors impact both commodity prices and volumes. Commodity prices historically have been volatile and continue to be volatile. Crude oil prices have generally remained at favorable levels, while NGL prices remain modest due to increasing supplies. Natural gas prices have recovered somewhat recently, but remain soft relative to historical levels. Although we have not experienced a significant impact to our natural gas throughput volumes as a result of decreased commodity prices, if commodity prices remain weak 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 firm in areas with liquids rich gas. Drilling remains weak in certain areas with dry gas where relatively lower commodity 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. We use direct NGL hedges to mitigate a significant portion of our NGL price exposure; however, weakening of the relationship of natural gas liquids to crude oil prices does modestly impact the effectiveness of our hedging program to mitigate our exposure to price fluctuations where we use crude oil to hedge our NGL price exposure.

NGL prices are also impacted by the demand from petro-chemical and refining industries. The petrochemical industry is making significant investment in building or expanding facilities to convert chemical plants from heavier oil-based feed stock to lighter NGL-based feed stock, including ethane. This increased demand should support increasing ethane supplies. In addition, propane export facilities are also being expanded or built, which is expected to support increasing propane supply. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

The global economic outlook continues to be cause for concern for U.S. financial markets and businesses and investors alike. A further slowdown in global economic growth or a potential liquidity crisis may lead to further declines in commodity prices. This uncertainty may contribute to volatility in financial and commodity markets. The amount of NGLs we produce, fractionate, transport, sell and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver NGLs are capacity constrained and cannot, or will not, accept the NGLs. Recent capacity expansions are coming online, which we believe will mitigate the risk of these NGL capacity constraints.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low historical costs have enabled us to continue executing our multi-faceted growth strategy, with an emphasis on dropdowns from DCP Midstream, LLC. Our multi-faceted growth strategy may take numerous forms such as accretive dropdown opportunities from DCP Midstream, LLC, third-party acquisitions, joint venture opportunities and organic build opportunities within our footprint. Dropdowns from DCP Midstream, LLC since the beginning of 2012 totaled approximately \$2.0 billion.

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Some of our recent growth projects include the following:

On August 5, 2013, we completed the acquisition of DCP LaSalle Plant, LLC, or LaSalle, from DCP Midstream, LLC for aggregate consideration of \$209 million, subject to certain purchase price adjustments. LaSalle is a 110 MMcf/d natural gas processing plant currently under construction with plans to expand to a 160 MMcf/d. We also entered into a 15-year fee-based agreement with an affiliate of DCP Midstream, LLC, which provides us with a fixed demand charge. The fee-based agreement also provides us with a throughput fee on all volumes processed at LaSalle. The processing agreement commences with commercial operations of the new plant, which is expected to be in-service in the second half of 2013.

On August 5, 2013, we also completed the acquisition of Front Range, LLC, or Front Range, from DCP Midstream, LLC for aggregate consideration of \$86 million, subject to certain purchase price adjustments. Front Range owns a 33.33% equity method interest in Front Range Pipeline LLC, a joint venture with affiliates of Enterprise Products Partners L.P. and Anadarko Petroleum Corporation, which was formed to construct a new NGL pipeline that will originate in the DJ Basin and extend approximately 435 miles to Skellytown, Texas. The pipeline operator expects the NGL pipeline to be mechanically complete in the fourth quarter of 2013.

On March 28, 2013, we acquired an additional 46.67% interest in DCP SC Texas GP, or the Eagle Ford system, from DCP Midstream, LLC and fixed price commodity derivative hedges for a three-year period for aggregate consideration of \$626 million. Our 80% interest in the construction of the Goliad 200 MMcf/d natural gas processing plant, including direct commodity price hedges, representing a total investment of approximately \$290 million, is expected to be in-service in the first quarter of 2014.

Our construction of our wholly-owned Eagle 200 MMcf/d natural gas processing plant is complete and has commenced operations. Our expansion plan for the Discovery natural gas gathering pipeline system is also progressing and is expected to be completed in the middle of 2014. 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 dropdown opportunities with DCP Midstream, LLC. In March 2013, we raised \$494 million, net of commissions and offering costs, through a public equity offering and \$490 million, net of underwriters' fees, related expenses, and unamortized discounts, through a public debt offering of 3.875% 10-year Senior Notes, which were used to finance our growth opportunities. During the three and six months ended June 30, 2013, we issued 1,408,547 of our common units pursuant to the equity distribution agreement and received proceeds of \$67 million, net of commissions and accrued offering costs of \$2 million, which were used to finance growth opportunities and for general corporate purposes. On June 14, 2013, we filed a shelf registration statement on Form S-3 with the Securities and Exchange Commission, or the SEC, with a maximum offering price of \$300 million, which became effective on June 27, 2013. The shelf registration statement will allow us to issue additional common units. As of June 30, 2013, we have issued no securities under this registration statement. As of June 30, 2013, the unused capacity under the Credit Agreement was \$849 million, of which \$847 million was available for general working capital purposes, providing liquidity to continue to execute on our growth plans.

We raised our distributions for the quarter, resulting in a 6% increase in our quarterly distribution rate over the rate declared for the second quarter of 2012. The distributions reflect our business results as well as our recent execution on growth opportunities.

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General Trends and Outlook

In the remainder of 2013, 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 currently representing approximately 50% 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 \$30 million and \$35 million, and approved expenditures for expansion capital of approximately \$500 million, for the year ending December 31, 2013. Expansion capital expenditures include construction of the Texas Express Pipeline and Discovery's Keathley Canyon Connector, which are shown as investments in unconsolidated affiliates, construction of the Goliad plant within the Eagle Ford system and the Eagle plant, expansion and upgrades to our Southeast Texas complex, the Marysville NGL storage project, expansion of our Cheasapeake facility and acquisitions. The board of directors may, at its discretion, approve additional growth capital during the year.

In the remainder of 2013, 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 substantial emphasis on our dropdown 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" included as Exhibit 99.2 to our Current Report on Form 8-K filed with the SEC on June 14, 2013.

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 80% interest in the Eagle Ford system and 100% interest in Southeast Texas for all periods presented, similar to the pooling method. 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.



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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, operating revenues, 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 operating revenues, 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;
- viability and performance of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities; and

- 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 gross margin, segment gross margin and adjusted segment EBITDA to its most directly comparable GAAP financial measure.



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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. 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:

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Reconciliation of Non-GAAP Measures	(Millions)			
Reconciliation of net income attributable to partners to gross margin:				
Net income attributable to partners	\$ 102	\$ 85	\$ 154	\$ 119
Interest expense	14	11	26	24
Income tax expense	—	—	1	1
Operating and maintenance expense	51	50	96	92
Depreciation and amortization expense	23	15	43	49
General and administrative expense	16	17	32	36
Other expense	—	—	4	—
Earnings from unconsolidated affiliates	(8	) (2	) (16	) (8
Net income attributable to noncontrolling interests	4	2	7	6
Gross margin	\$ 202	\$ 178	\$ 347	\$ 319
Non-cash commodity derivative mark-to-market (a)	\$ 58	\$ 65	\$ 48	\$ 42
Reconciliation of segment net income attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net income attributable to partners	\$ 111	\$ 106	\$ 150	\$ 146
Operating and maintenance expense	43	42	81	77
Depreciation and amortization expense	21	14	39	45
Earnings from unconsolidated affiliates	(1	) (2	) (1	) (8
Net income attributable to noncontrolling interests	4	2	7	6
Segment gross margin	\$ 178	\$ 162	\$ 276	\$ 266
Non-cash commodity derivative mark-to-market (a)	\$ 58	\$ 49	\$ 49	\$ 26
NGL Logistics segment:				
Segment net income attributable to partners	\$ 20	\$ 10	\$ 42	\$ 20
Operating and maintenance expense	4	4	8	8
Depreciation and amortization expense	2	1	3	3
Earnings from unconsolidated affiliates	(7	) —	(15	) —
Segment gross margin	\$ 19	\$ 15	\$ 38	\$ 31
Wholesale Propane Logistics segment:				
Segment net income (loss) attributable to partners	\$ 1	\$ (3	) \$ 21	\$ 14
Operating and maintenance expense	4	4	7	7
Depreciation and amortization expense	—	—	1	1
Other expense	—	—	4	—
Segment gross margin	\$ 5	\$ 1	\$ 33	\$ 22
Non-cash commodity derivative mark-to-market (a)	\$ —	\$ 16	\$ (1	) \$ 16

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



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	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(Millions)			
Reconciliation of net income attributable to partners to adjusted segment EBITDA:				
Natural Gas Services segment:				
Segment net income attributable to partners (a)	\$111	\$106	\$150	\$146
Non-cash commodity derivative mark-to-market	(58	) (49	) (49	) (26
Depreciation and amortization expense	21	14	39	45
Noncontrolling interest on depreciation and income tax	(2	) (2	) (3	) (4
Adjusted Segment EBITDA	\$72	\$69	\$137	\$161
NGL Logistics segment:				
Segment net income attributable to partners	\$20	\$10	\$42	\$20
Depreciation and amortization expense	2	1	3	3
Adjusted Segment EBITDA	\$22	\$11	\$45	\$23
Wholesale Propane Logistics segment:				
Segment net income (loss) attributable to partners (b)	\$1	\$(3	) \$21	\$14
Non-cash commodity derivative mark-to-market	—	(16	) 1	(16
Depreciation and amortization expense	—	—	1	1
Adjusted Segment EBITDA	\$1	\$(19	) \$23	\$(1

Includes \$2 million lower of cost or market adjustments for the three and six months ended June 30, 2013 and no (a) lower of cost or market adjustments for the three months ended June 30, 2012. We recognized \$4 million of lower of cost or market adjustments during the six months ended June 30, 2012.

Includes \$1 million and \$14 million of lower of cost or market adjustments for the three months ended June 30, (b) 2013 and 2012, respectively. We recognized \$1 million and \$15 million of lower of cost or market adjustments during the six months ended June 30, 2013 and 2012, respectively.

**Critical Accounting Policies and Estimates**

Our critical accounting policies and estimates are described in Item 7 included as Exhibit 99.2 to our Current Report on Form 8-K filed on June 14, 2013. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and six months ended June 30, 2013 are the same as those described in our Current Report on Form 8-K filed on June 14, 2013.

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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 and six months ended June 30, 2013 and 2012. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2013 vs. 2012			Variance Six Months 2013 vs. 2012		
	2013	2012 (a)	2013 (a)	2012 (a)(b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent		
(Millions, except as indicated)										
Operating revenues (c):										
Natural Gas Services	\$703	\$580	1,260	1,197	\$123	21 %	\$63	5 %		
NGL Logistics	19	15	38	31	4	27 %	7	23 %		
Wholesale Propane Logistics	53	73	208	277	(20)	(27)%	(69)	(25)%		
Total operating revenues	775	668	1,506	1,505	107	16 %	1	—		
Gross margin (d):										
Natural Gas Services	178	162	276	266	16	10 %	10	4 %		
NGL Logistics	19	15	38	31	4	27 %	7	23 %		
Wholesale Propane Logistics	5	1	33	22	4	400 %	11	50 %		
Total gross margin	202	178	347	319	24	13 %	28	9 %		
Operating and maintenance expense	(51)	(50)	(96)	(92)	1	2 %	4	4 %		
Depreciation and amortization expense	(23)	(15)	(43)	(49)	8	53 %	(6)	(12)%		
General and administrative expense	(16)	(17)	(32)	(36)	(1)	(6)%	(4)	(11)%		
Other expense	—	—	(4)	—	—	—	4	100 %		
Earnings from unconsolidated affiliates (e)	8	2	16	8	6	300 %	8	100 %		
Interest expense	(14)	(11)	(26)	(24)	3	27 %	2	8 %		
Income tax expense	—	—	(1)	(1)	—	—	—	—		
Net income attributable to noncontrolling interests	(4)	(2)	(7)	(6)	2	100 %	1	17 %		
Net income attributable to partners	\$102	\$85	\$154	\$119	\$17	20 %	\$35	29 %		
Other data:										
Non-cash commodity derivative mark-to-market	\$58	\$65	48	42	\$(7)	(11)%	\$6	14 %		
Natural gas throughput (MMcf/d) (e)	2,264	2,216	2,285	2,250	48	2 %	35	2 %		
NGL gross production (Bbls/d) (e)	112,785	105,282	113,446	105,709	7,503	7 %	7,737	7 %		
NGL pipelines throughput (Bbls/d) (e)	93,306	72,786	88,800	77,740	20,520	28 %	11,060	14 %		
Propane sales volume (Bbls/d)	12,286	11,641	23,024	23,010	645	6 %	14	—		

(a)

Includes our 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 33.33% interest in the Eagle Ford system on November 2, 2012, and a 46.67% interest on March 28, 2013.

(b) Includes our 100% interest in Southeast Texas, retrospectively adjusted. We acquired a 33.33% interest in Southeast Texas on January 1, 2011, and a 66.67% interest on March 30, 2012.

(c) Operating revenues include the impact of commodity derivative activity.

Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs. 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.

(d) Includes our share, based on our ownership percentage, of the throughput volumes, NGL production and earnings of all unconsolidated affiliates. Earnings for Discovery and the Mont Belvieu 1 fractionator include the amortization of the net difference between the carrying amount of the investment and the underlying equity of the investment.



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Three Months Ended June 30, 2013 vs. Three Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues increased \$107 million in 2013 compared to 2012 primarily as a result of the following:

\$68 million increase primarily attributable to increased natural gas prices and prices for physical sales related to our natural gas storage and pipeline assets, partially offset by decreased NGL prices;

\$36 million increase primarily attributable to increased volumes at our Eagle Ford system and our fee-based wholly-owned Eagle plant, partially offset by decreased volumes for physical sales related to our natural gas storage and pipeline assets, and a plant turnaround at our Eagle Ford system; and

\$11 million increase attributable to increased activity at our NGL storage facility and increased throughput on certain of our pipelines within our NGL Logistics and Natural Gas Services segments, as well as the operation of our fee-based wholly-owned Eagle plant.

These increases were partially offset by:

\$4 million decrease attributable to lower propane prices, partially offset by increased volumes in our Wholesale Propane segment. 2012 results reflect near record warm weather; and

\$4 million decrease related to commodity derivative activity as a result of a \$16 million decrease in our Wholesale Propane segment, partially offset by a \$12 million increase in our Natural Gas Services segment. This net decrease includes a \$6 million decrease in unrealized commodity derivative gains, partially offset by a \$2 million increase in realized cash settlement gain.

Gross Margin — Gross margin increased \$24 million in 2013 compared to 2012, primarily as a result of the following:

\$16 million increase for our Natural Gas Services segment, primarily related to higher volume at our Eagle Ford system and the operation of our fee-based wholly-owned Eagle plant and increased commodity derivative activities, partially offset by lower NGL prices, a lower of cost or market adjustment recognized in our natural gas storage and pipeline assets, and a plant turnaround at our Eagle Ford system;

\$4 million increase for our NGL Logistics segment as result of increased activity at our NGL storage facility and increased throughput on certain of our pipelines; and

\$4 million increase for our Wholesale Propane Logistics segment, primarily due to increased unit margins, partially offset by a decrease related to commodity derivative activities. 2012 results reflect a non-cash lower of cost or market inventory adjustment of \$14 million and reduced volumes as a result of near record warm weather.

Operating and Maintenance Expense — Operating and maintenance expense remained relatively constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2013 compared to 2012 primarily as a result of growth in our business.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, 20% ownership of the Mont Belvieu 1 fractionator and 12.5% ownership of the Mont Belvieu Enterprise fractionator, increased in 2013 compared to 2012 primarily as a result of the acquisition of the Mont Belvieu fractionators in July 2012, partially offset by lower results at Discovery due to lower NGL prices. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Net income attributable to noncontrolling interests — Net income attributable to noncontrolling interests increased in 2013 compared to 2012, primarily as a result of higher volumes at our Eagle Ford system, partially offset by a plant turnaround at our Eagle Ford system.

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Six Months Ended June 30, 2013 vs. Six Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues remained relatively constant in 2013 compared to 2012 primarily as a result of the following:

\$25 million increase primarily attributable to increased natural gas prices and prices for physical sales related to our natural gas storage and pipeline assets, partially offset by decreased NGL prices;

\$22 million increase attributable to increased activity at our NGL storage facility and increased throughput on certain of our pipelines within our NGL Logistics and Natural Gas Services segments, as well as the operation of our fee-based wholly-owned Eagle plant;

\$6 million increase primarily attributable to increased volumes on our Eagle Ford system and across certain assets, partially offset by contractual amendments such that certain revenues changed from a gross presentation to a net fee presentation, decreased volumes for physical sales related to our natural gas storage and pipeline assets, and a plant turnaround at our Eagle Ford system; and

\$1 million increase related to commodity derivative activity as a result of a \$17 million increase in our Natural Gas Services segment, partially offset by a \$16 million decrease in our Wholesale Propane segment. This net increase includes a \$6 million increase in unrealized commodity derivative gains, partially offset by a \$5 million decrease in realized cash settlement gain.

These increases were partially offset by:

\$53 million decrease attributable to lower propane prices in our Wholesale Propane Logistics segment.

Gross Margin — Gross margin increased \$28 million in 2013 compared to 2012, primarily as a result of the following:

\$11 million increase for our Wholesale Propane Logistics segment, primarily due to increased unit margins and exporting propane from our Chesapeake terminal, partially offset by a decrease related to commodity derivative activities and suspending the import of supply. 2012 results reflect a non-cash lower of cost or market inventory adjustment of \$15 million and reduced demand as a result of near record warm winter;

\$10 million increase for our Natural Gas Services segment, primarily related to increased commodity derivative activities, higher volume at our Eagle Ford system and the operation of our fee-based wholly-owned Eagle plant, higher unit margins associated with our natural gas storage and pipeline assets, and a decrease in the lower of cost or market adjustment recognized in 2013, partially offset by decreased NGL prices and a plant turnaround at our Eagle Ford system; and

\$7 million increase for our NGL Logistics segment as a result of increased activity at our NGL storage facility and increased throughput on certain of our pipelines.

Operating and Maintenance Expense — Operating and maintenance expense remained relatively constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization expense decreased in 2013 compared to 2012 primarily as a result of a change in the estimated depreciable lives of our fixed assets in the second quarter of 2012.

The key contributing factors to the change in depreciable lives was an increase in the producers' estimated remaining economically recoverable reserves, resulting from widespread application of techniques, such as hydraulic fracturing and horizontal drilling, that improve commodity production in the regions our assets serve. Advances in extraction processes, along with improved technology used to locate commodity reserves, is giving producers greater access to unconventional commodities.

General and Administrative Expense — General and administrative expense decreased in 2013 compared to 2012 primarily due to the difference in the Eagle Ford system's ownership structure in each period.

Other Expense — Other expense in 2013 represents a write off of approximately \$4 million in construction work in progress due to discontinued projects.

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Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, 20% ownership of the Mont Belvieu 1 fractionator and 12.5% ownership of the Mont Belvieu Enterprise fractionator, increased in 2013 compared to 2012 primarily as a result of the acquisition of the Mont Belvieu fractionators in July 2012, partially offset by lower results at Discovery due to lower NGL prices, reduced throughput volumes and timing of expenditures. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Net income attributable to noncontrolling interests — Net income attributable to noncontrolling interests remained relatively constant in 2013 compared to 2012, primarily as a result of higher volumes at our Eagle Ford system, partially offset by a plant turnaround at our Eagle Ford system.

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## Results of Operations — Natural Gas Services Segment

This segment consists of our Southeast Texas system, our East Texas system, our Michigan system, a 75% operating interest in our Colorado system, Northern Louisiana system, a 40% interest in Discovery, our Southern Oklahoma system, our Wyoming system, an 80% interest in our Eagle Ford system, and our wholly-owned Eagle plant:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2013 vs. 2012		Variance Six Months 2013 vs. 2012			
	2013	2012 (a)	2013 (a)	2012 (a)(b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent		
(Millions, except as indicated)										
Operating revenues:										
Sales of natural gas, NGLs and condensate	\$590	\$486	\$1,104	\$1,073	\$104	21	%	\$31	3	%
Transportation, processing and other	42	35	86	71	7	20	%	15	21	%
Gains from commodity derivative activity	71	59	70	53	12	20	%	17	32	%
Total operating revenues	703	580	1,260	1,197	123	21	%	63	5	%
Purchases of natural gas and NGLs	(525 )	(418 )	(984 )	(931 )	107	26	%	53	6	%
Segment gross margin (c)	178	162	276	266	16	10	%	10	4	%
Operating and maintenance expense	(43 )	(42 )	(81 )	(77 )	1	2	%	4	5	%
Depreciation and amortization expense	(21 )	(14 )	(39 )	(45 )	7	50	%	(6 )	(13 )	%
Earnings from unconsolidated affiliates (d)	1	2	1	8	(1 )	(50 )	%	(7 )	(88 )	%
Segment net income	115	108	157	152	7	6	%	5	3	%
Segment net income attributable to noncontrolling interests	(4 )	(2 )	(7 )	(6 )	2	100	%	1	17	%
Segment net income attributable to partners	\$111	\$106	\$150	\$146	\$5	5	%	\$4	3	%
Other data:										
Non-cash commodity derivative mark-to-market	\$58	\$49	\$49	\$26	\$9	18	%	\$23	88	%
Natural gas throughput (MMcf/d) (d)	2,264	2,216	2,285	2,250	48	2	%	35	2	%
NGL gross production (Bbls/d) (d)	112,785	105,282	113,446	105,709	7,503	7	%	7,737	7	%

(a) Includes our 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 33.33% interest in the Eagle Ford system on November 2, 2012, and a 46.67% interest on March 28, 2013.

(b) Includes our 100% interest in Southeast Texas, retrospectively adjusted. We acquired a 33.33% interest in Southeast Texas on January 1, 2011, and a 66.67% interest on March 30, 2012.

(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, NGL production and earnings of all unconsolidated affiliates. Earnings for Discovery include the amortization of the net difference between the carrying amount of the investment and the underlying equity of the investment.

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Three Months Ended June 30, 2013 vs. Three Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues increased \$123 million in 2013 compared to 2012, primarily as a result of the following:

• \$90 million increase attributable to increased natural gas prices;

• \$54 million increase primarily attributable to increased volumes at our Eagle Ford system and our fee-based wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system;

• \$37 million increase attributable to increased prices for physical sales related to our natural gas storage and pipeline assets;

• \$12 million increase related to commodity derivative activity. This includes an increase in unrealized commodity derivative gains in 2013 compared to 2012 of \$9 million due to movements in forward prices of commodities, and an increase in realized cash settlement gains in 2013 compared to 2012 of \$3 million; and

• \$7 million increase in fee revenue attributable to the operation of our fee-based wholly-owned Eagle plant.

These increases were partially offset by:

• \$59 million decrease attributable to decreased NGL prices; and

• \$18 million decrease attributable to decreased volumes for physical sales related to our natural gas storage and pipeline assets.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased \$107 million in 2013 compared to 2012 primarily as a result of higher natural gas prices and increased volumes across certain assets, partially offset by a plant turnaround at our Eagle Ford system and decreased NGL prices.

Segment Gross Margin — Segment gross margin increased \$16 million in 2013 compared to 2012, primarily as a result of the following:

• \$14 million increase as a result of higher volume at our Eagle Ford system and the operation of our fee-based wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system; and

• \$12 million increase related to commodity derivative activities as discussed above.

These increases were partially offset by:

• \$8 million decrease as a result of lower NGL prices, which reflects the unhedged portion of the Eagle Ford system associated with DCP Midstream, LLC's ownership. During the three months ended June 30, 2013 and 2012, DCP Midstream, LLC's interest in the Eagle Ford system was 20% and 100%, respectively; and

• \$2 million decrease associated with a lower of cost or market adjustment recognized in our natural gas storage and pipeline assets.

Operating and Maintenance Expense — Operating and maintenance expense remained relatively constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2013 compared to 2012 primarily as a result of growth in our business.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, decreased in 2013 compared to 2012 primarily as a result of lower results due to lower NGL prices.

Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

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Segment net income attributable to noncontrolling interests - Segment net income attributable to noncontrolling interests increased in 2013 compared to 2012, primarily as a result of higher volumes at our Eagle Ford system, partially offset by a plant turnaround at our Eagle Ford system.

Natural Gas Throughput - Natural gas throughput increased in 2013 compared to 2012 primarily as a result of higher volumes due to the operation of our wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system and lower volumes across certain assets.

NGL Gross Production - NGL production increased in 2013 compared to 2012 primarily as a result of higher volumes due to the operation of our wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system and lower volumes across certain assets.

Six Months Ended June 30, 2013 vs. Six Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues increased \$63 million in 2013 compared to 2012, primarily as a result of the following:

\$124 million increase attributable to increased natural gas prices;

\$61 million increase attributable to increased gas prices for physical sales related to our natural gas storage and pipeline assets;

\$19 million increase primarily attributable to increased volumes at our Eagle Ford system and across certain assets, partially offset by contractual amendments such that certain revenues changed from a gross presentation to a net fee presentation and a plant turnaround at our Eagle Ford system;

\$17 million increase related to commodity derivative activity. This includes an increase in unrealized commodity derivative gains in 2013 compared to 2012 of \$23 million due to movements in forward prices of commodities, partially offset by a decrease in realized cash settlement gains in 2013 compared to 2012 of \$6 million; and

\$15 million increase in fee revenue attributable to contractual amendments such that certain revenues changed from a gross presentation to a net fee presentation and the operation of our fee-based wholly-owned Eagle plant.

These increases were partially offset by:

\$160 million decrease attributable to decreased NGL prices; and

\$13 million decrease attributable to decreased volumes for physical sales related to our natural gas storage and pipeline assets.

Purchases of Natural Gas and NGLs - Purchases of natural gas and NGLs increased \$53 million in 2013 compared to 2012 primarily as a result of higher natural gas prices, increased volumes at our Eagle Ford system and across certain assets, partially offset by contractual amendments such that certain revenues changed from a gross presentation to a net fee presentation, decreased NGL prices and a plant turnaround at our Eagle Ford system.

Segment Gross Margin — Segment gross margin increased \$10 million in 2013 compared to 2012, primarily as a result of the following:

\$17 million increase related to commodity derivative activities as discussed above;

\$13 million increase as a result of higher volumes at our Eagle Ford system and the operation of our fee-based wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system; and

\$9 million increase attributable to higher unit margins associated with our natural gas storage and pipeline assets and a decrease in the lower of cost or market adjustment recognized in 2013.

These increases were partially offset by:

\$29 million decrease as a result of lower NGL prices, which reflects the unhedged portion of the Eagle Ford and Southeast Texas systems associated with DCP Midstream, LLC's ownership during each of the six months ended June 30, 2013 and 2012.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2013 compared to 2012 primarily as a result of growth and timing of expenditures.

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**Depreciation and Amortization Expense** — Depreciation and amortization expense decreased in 2013 compared to 2012 primarily as a result of a change in the estimated depreciable lives of our fixed assets in the second quarter of 2012, partially offset by growth in our business. The key contributing factors to the change in depreciable lives was an increase in the producers' estimated remaining economically recoverable reserves, resulting from widespread application of techniques, such as hydraulic fracturing and horizontal drilling, that improve commodity production in the regions our assets serve. Advances in extraction processes, along with improved technology used to locate commodity reserves, is giving producers greater access to unconventional commodities.

**Earnings from Unconsolidated Affiliates** - Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery, decreased in 2013 compared to 2012 primarily as a result of lower results due to lower NGL prices, reduced throughput volumes and timing of expenditures. 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 remained relatively constant in 2013 compared to 2012, primarily as a result of higher volumes at our Eagle Ford system, partially offset by a plant turnaround at our Eagle Ford system.

**Natural Gas Throughput** - Natural gas throughput increased in 2013 compared to 2012 primarily as a result of higher volumes due to the operation of our wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system and lower volumes across certain assets.

**NGL Gross Production** - NGL production increased in 2013 compared to 2012 primarily as a result of higher volumes due to the operation of our wholly-owned Eagle plant, partially offset by a plant turnaround at our Eagle Ford system and lower volumes across certain assets.

**Results of Operations — NGL Logistics Segment**

This segment includes our Seabreeze, Wilbreeze, Wattenberg and Black Lake transportation pipelines, our 10% interest in the Texas Express NGL pipeline, our Marysville NGL storage facility, our DJ Basin NGL fractionators, our 12.5% interest in the Mont Belvieu Enterprise fractionator and our 20% interest in the Mont Belvieu 1 fractionator:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2013 vs. 2012		Variance Six Months 2013 vs. 2012		
	2013	2012	2013	2012	Increase (Decrease)	Percent	Increase (Decrease)	Percent	
(Millions, except as indicated)									
Operating revenues:									
Sales of NGLs	\$—	\$—	\$—	\$—	\$—	—	\$—	—	
Transportation, processing and other	19	15	38	31	4	27	% 7	23	%
Total operating revenues	19	15	38	31	4	27	% 7	23	%
Purchases of NGLs	—	—	—	—	—	—	—	—	
Segment gross margin (a)	19	15	38	31	4	27	% 7	23	%
Operating and maintenance expense	(4 )	(4 )	(8 )	(8 )	—	—	—	—	
Depreciation and amortization expense	(2 )	(1 )	(3 )	(3 )	1	100	% —	—	
Earnings from unconsolidated affiliates (b)	7	—	15	—	7	100	% 15	100	%
Segment net income attributable to partners	\$20	\$10	\$42	\$20	\$10	100	% \$22	110	%
Other data:									
NGL pipelines throughput (Bbls/d) (b)	93,306	72,786	88,800	77,740	20,520	28	% 11,060	14	%



- (a) Segment gross margin consists of total operating revenues less purchases of NGLs. Please read “Reconciliation of Non-GAAP Measures” above.
- (b) Includes our share, based on our ownership percentage, of the throughput volumes and earnings of unconsolidated affiliates.

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Three Months Ended June 30, 2013 vs. Three Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues increased in 2013 compared to 2012 as result of increased activity at our NGL storage facility and increased throughput on certain of our pipelines.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 as result of increased activity at our NGL storage facility and increased throughput on certain of our pipelines.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization remained relatively constant in 2013 compared to 2012.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 fractionator and 12.5% ownership of the Mont Belvieu Enterprise fractionator, increased in 2013 compared to 2012 as a result of the acquisition of the Mont Belvieu fractionators in July 2012.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2013 compared to 2012 as a result of volume growth on our pipelines.

Six Months Ended June 30, 2013 vs. Six Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues increased in 2013 compared to 2012 as result of increased activity at our NGL storage facility and increased throughput on certain of our pipelines.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 as result of increased activity at our NGL storage facility and increased throughput on certain of our pipelines.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2013 compared to 2012.

Depreciation and Amortization Expense — Depreciation and amortization expense remained constant in 2013 compared to 2012.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing 20% ownership of the Mont Belvieu 1 fractionator and 12.5% ownership of the Mont Belvieu Enterprise fractionator, increased in 2013 compared to 2012 as a result of the acquisition of the Mont Belvieu fractionators in July 2012.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2013 compared to 2012 as a result of volume growth on our pipelines

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## 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 June 30,		Six Months Ended June 30,		Variance Three Months 2013 vs. 2012			Variance Six Months 2013 vs. 2012		
	2013	2012	2013	2012	Increase (Decrease)	Percent	Increase (Decrease)	Percent		
(Millions, except as indicated)										
Operating revenues:										
Sales of propane	\$53	\$57	\$207	\$260	\$(4)	(7)%	\$(53)	(20)%		
Other	—	—	—	—	—	—	—	—		
Gains from commodity derivative activity	—	16	1	17	(16)	(100)%	(16)	(94)%		
Total operating revenues	53	73	208	277	(20)	(27)%	(69)	(25)%		
Purchases of propane	(48)	(72)	(175)	(255)	(24)	(33)%	(80)	(31)%		
Segment gross margin (a)	5	1	33	22	4	400%	11	50%		
Operating and maintenance expense	(4)	(4)	(7)	(7)	—	—	—	—		
Depreciation and amortization expense	—	—	(1)	(1)	—	—	—	—		
Other expense	—	—	(4)	—	—	—	4	100%		
Segment net income (loss) attributable to partners	\$1	\$(3)	\$21	\$14	\$4	133%	\$7	50%		
Other data:										
Non-cash commodity derivative mark-to-market	\$—	\$16	\$(1)	\$16	\$(16)	(100)%	\$(17)	(106)%		
Propane sales volume (Bbls/d)	12,286	11,641	23,024	23,010	645	6%	14	—		

(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 June 30, 2013 vs. Three Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues decreased by \$20 million in 2013 compared to 2012, primarily as a result of the following:

\$16 million decrease related to commodity derivative activity, which represents a decrease in unrealized commodity derivative gains in 2013 compared to 2012 due to movements in forward prices of commodities; and

\$7 million decrease attributable to lower propane prices.

These decreases were partially offset by:

\$3 million increase attributable to increased volumes. 2012 results reflect reduced volumes as a result of near record warm weather.

Purchases of Propane — Purchases of propane decreased in 2013 compared to 2012 primarily due to lower propane prices, which impacts both sales and purchases, and a 2012 non-cash lower of cost or market inventory adjustment of \$14 million, partially offset by reduced volumes in 2012 as a result of near record warm weather.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 primarily due to increased unit margins, partially offset by a \$16 million decrease related to commodity derivative activities as discussed above. 2012 results reflect a non-cash lower of cost or market inventory adjustment of \$14 million and reduced volumes as a result of near record warm weather.

Propane Sales Volume — Propane sales volumes increased in 2013 compared to 2012. 2012 results reflect reduced demand as a result of near record warm winter.

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Six Months Ended June 30, 2013 vs. Six Months Ended June 30, 2012

Total Operating Revenues — Total operating revenues decreased by \$69 million in 2013 compared to 2012, primarily as a result of the following:

\$53 million decrease attributable to lower propane prices; and

\$16 million decrease related to commodity derivative activity. This includes a decrease in unrealized commodity derivative gains in 2013 compared to 2012 of \$17 million due to movements in forward prices of commodities, partially offset by an increase in realized cash settlement gains in 2013 compared to 2012 of \$1 million.

Purchases of Propane — Purchases of propane decreased in 2013 compared to 2012 primarily due to lower propane prices, which impacts both sales and purchases, suspending the import of supply and a 2012 non-cash lower of cost or market inventory adjustment of \$15 million, partially offset by the exporting of propane from our Chesapeake terminal and reduced demand in 2012 as a result of near record warm winter.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 primarily due to increased unit margins and exporting propane from our Chesapeake terminal, partially offset by a \$16 million decrease related to commodity derivative activities as discussed above, suspending the import of supply, and a \$1 million non-cash lower of cost or market inventory adjustment recorded in 2013. 2012 results reflect a non-cash lower of cost or market inventory adjustment of \$15 million and reduced demand as a result of near record warm winter.

Other Expense — Other expense in 2013 represents a write off of approximately \$4 million in construction work in progress due to a discontinued project.

Propane Sales Volume — Propane sales volumes remained relatively constant in 2013 compared to 2012.

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 Agreement;

borrowings under term loans;

issuance of additional common units, including issuances we may make to DCP Midstream, LLC;

debt offerings; and

letters of credit.

We anticipate our more significant uses of resources to include:

quarterly distributions to our unitholders and general partner;

capital expenditures;

contributions to our unconsolidated affiliates to finance our share of their capital expenditures;

business and asset acquisitions, including contributions from DCP Midstream, LLC; 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 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.

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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, impact our credit ratings, 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, public debt, and the issuance of our common units.

Our Credit Agreement consists of a senior unsecured revolving credit facility with capacity of \$1 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 August 2, 2013, we had approximately \$496 million of unused capacity under the Credit Agreement.

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 Part 1, Item 3 herein and "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" in our 2012 Form 10-K.

On March 14, 2013, we issued \$500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of \$490 million, net of underwriters' fees, related expenses and unamortized discounts totaling \$10 million, which we used to fund a portion of the purchase price for the acquisition of an additional 46.67% interest in the Eagle Ford system.

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, of common units having an aggregate offering amount of up to \$150 million. During the three and six months ended June 30, 2013, we issued 1,408,547 of our common units pursuant to the equity distribution agreement and received proceeds of \$67 million, net of commissions and accrued offering costs of \$2 million, which were used to finance growth opportunities and general corporate purposes. As of June 30, 2013, no common units remained available for sale pursuant to this equity distribution agreement.

On June 14, 2013, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of \$300 million, which became effective on June 27, 2013. The shelf registration statement will allow us to issue additional common units. As of June 30, 2013, we have issued no securities under this registration statement.

In March 2013, we issued 2,789,739 common units to DCP Midstream, LLC as partial consideration for 46.67% interest in the Eagle Ford system.

In March 2013, we issued 12,650,000 common units at \$40.63 per unit. We received proceeds of \$494 million, net of offering costs.

The counterparties to certain 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 August 2, 2013, 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. The counterparty to our remaining commodity swaps contracts is DCP Midstream, LLC.

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**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 other long-term assets. We had working capital of \$10 million as of June 30, 2013, compared to working capital of \$23 million as of December 31, 2012. Included in these working capital amounts are net derivative working capital assets of \$75 million and \$18 million as of June 30, 2013 and December 31, 2012, 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 June 30, 2013, we had \$9 million in cash and cash equivalents. Of this balance, \$2 million was held by consolidated subsidiaries we do not wholly own. Other than the cash held by these subsidiaries, this cash balance was available for general partnership purposes.

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

	Six Months Ended	
	June 30,	
	2013	2012
	(Millions)	
Net cash provided by operating activities	\$270	\$47
Net cash used in investing activities	\$(768)	\$(550)
Net cash provided by financing activities	\$505	\$501

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 \$23 million for our net hedge cash settlements for the six months ended June 30, 2013, of which less than \$1 million was associated with rebalancing our portfolio, and \$28 million for our net hedge cash settlements for the six months ended June 30, 2012.

We received cash distributions from unconsolidated affiliates of \$22 million and \$8 million during the six months ended June 30, 2013 and 2012, respectively. Distributions exceeded earnings by \$6 million for the six months ended June 30, 2013, and by less than \$1 million for the six months ended June 30, 2012.

**Net Cash Used in Investing Activities** — Net cash used in investing activities during the six months ended June 30, 2013 was comprised of: (1) acquisition expenditures of \$486 million related to our acquisition of the additional 46.67% interest in the Eagle Ford system; (2) capital expenditures of \$195 million (our portion of which was \$171 million and the reimbursable projects portion was \$24 million); and (3) investments in unconsolidated affiliates of \$87 million. Net cash used in investing activities during the six months ended June 30, 2012 was comprised of: (1) acquisition expenditures of \$291 million, of which \$171 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, and \$120 million related to our acquisition of the remaining 49.9% interest in East Texas; (2) capital expenditures of \$218 million (our portion of which was \$186 million and the reimbursable projects portion was \$32 million); and (3) investments in unconsolidated affiliates of \$42 million; partially offset by (4) a return of investment from unconsolidated affiliate of \$1 million.





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Net Cash Provided by Financing Activities — Net cash provided by financing activities during the six months ended June 30, 2013 was comprised of: (1) proceeds from debt of \$1,079 million, offset by payments of \$960 million, for net borrowing of debt of \$119 million; (2) proceeds from the issuance of common units net of offering costs of \$563 million; (3) change in advances to predecessor from DCP Midstream, LLC of \$32 million; (4) contributions from noncontrolling interests of \$31 million; and (5) contributions from DCP Midstream, LLC of \$1 million; partially offset by (6) excess purchase price over acquired interests and commodity hedges of \$101 million; (7) distributions to our limited partners and general partner of \$123 million; (8) distributions to noncontrolling interests of \$10 million; (9) payment of deferred financing costs of \$4 million; and (10) distributions to DCP Midstream, LLC of \$3 million relating to capital expenditures for reimbursable projects.

Net cash provided by financing activities during the six months ended June 30, 2012 was comprised of: (1) proceeds from debt of \$1,008 million, offset by payments of \$807 million, for net borrowing of debt of \$201 million; (2) proceeds from the issuance of common units net of offering costs of \$248 million; (3) net change in advances to predecessor from DCP Midstream, LLC of \$102 million and from noncontrolling interest of \$28 million; and (4) contributions from DCP Midstream, LLC of \$7 million; partially offset by (5) distributions to our limited partners and general partner of \$79 million; (6) payment of deferred financing costs of \$3 million; and (7) distributions to noncontrolling interests of \$3 million.

During the six months ended June 30, 2013, total outstanding indebtedness under our \$1 billion Credit Agreement, which includes borrowings under our revolving credit facility and letters of credit issued under the Credit Agreement, was not less than \$151 million and did not exceed \$607 million. The weighted-average indebtedness outstanding for the six months ended June 30, 2013 was \$314 million.

As of June 30, 2013, we had unused capacity under the revolving credit facility of \$849 million, of which approximately \$847 million was available for general working capital purposes.

During the six months ended June 30, 2013, we had the following net movements on our revolving credit facility: \$441 million repayment financed by the issuance of 12,650,000 common units in March 2013; and \$14 million net repayment activity; partially offset by

\$80 million borrowings primarily to reimburse DCP Midstream, LLC for its proportionate share of the capital spent to date by the Eagle Ford system for the construction of the Goliad plant and for preformation capital expenditures.

During the six months ended June 30, 2012, we had the following net movements on our revolving credit facility: \$234 million repayment financed by the issuance of 5,148,500 common units in March 2012; partially offset by \$87 million net borrowings.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 10 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 \$30 million and \$35 million, and approved expenditures for expansion capital of approximately \$500 million, for the year ending December 31, 2013. 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 Goliad plant within the Eagle Ford system and the Eagle plant, expansion and upgrades to our Southeast Texas complex,

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the Marysville NGL storage project, expansion of our Cheasapeake facility and acquisitions. The board of directors may, at its discretion, approve additional growth capital during the year.

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

	Six months ended June 30, 2013			Six months ended June 30, 2012		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	\$10	\$161	\$171	\$9	\$177	\$186
Noncontrolling interest portion and reimbursable projects (a)	1	23	24	4	28	32
Total	\$11	\$184	\$195	\$13	\$205	\$218

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 \$87 million and \$42 million during the six months ended June 30, 2013 and 2012, respectively, 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 \$123 million during the six months ended June 30, 2013, as compared to \$79 million for the same period in 2012. 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 billion revolving credit facility that matures November 10, 2016. As of June 30, 2013, the outstanding balance on the revolving credit facility was \$150 million resulting in unused revolver capacity of \$849 million, of which approximately \$847 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 up to a maximum of \$500 million of outstanding letters of credit. At June 30, 2013 and December 31, 2012, we had \$1 million outstanding letters of credit issued under the Credit Agreement.

As of June 30, 2013, the weighted-average interest rate on our revolving credit facility was 1.45% per annum, excluding the impact of interest rate swaps.

**Description of Debt Securities** — On March 14, 2013, we issued \$500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of \$490 million, net of underwriters' fees, related expenses and unamortized discounts totaling \$10 million, which we used to fund the cash portion of the purchase price for the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes will be paid semi-annually on March 15 and September 15 of each year, commencing September 15, 2013. The notes will mature on March 15, 2023, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.



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On November 27, 2012, we issued \$500 million of our 2.50% 5-year Senior Notes due December 1, 2017. We received net proceeds of \$494 million, net of underwriters' fees, related expenses and unamortized discounts totaling \$6 million, which were used to repay our then-outstanding term loans. Interest on the notes will be paid semi-annually on June 1 and December 1 of each year, commencing June 1, 2013. The notes will mature on December 1, 2017, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

On March 13, 2012, we issued \$350 million of our 4.95% 10-year Senior Notes due April 1, 2022. We received net proceeds of \$346 million, net of underwriters' fees, related expenses and unamortized discounts totaling \$4 million, 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 Agreement. Interest on the notes is paid semi-annually on April 1 and October 1 of each year. 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 consolidated balance sheets and will be amortized over the term of the notes.

The 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 June 30, 2013, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(Millions)				
Long-term debt (a)	\$2,183	\$64	\$361	\$742	\$1,016
Operating lease obligations (b)	97	18	25	17	37
Purchase obligations (c)	270	193	54	23	—
Other long-term liabilities (d)	25	—	1	—	24
Total	\$2,575	\$275	\$441	\$782	\$1,077

(a) Includes interest payments on long-term debt that has been hedged and on debt securities that have been issued. These interest payments are \$57 million, \$111 million, \$92 million, and \$166 million for less than one year, one to three years, three to five years, and thereafter, respectively.

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 (b)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 June 30, 2013. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the 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 \$24 million of asset retirement obligations and \$1 million of environmental reserves recognized in the June 30, 2013 condensed consolidated balance sheet.

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

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## 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 2012 Form 10-K.

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 August 2, 2013:

## Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
July 2013 — December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	\$5.06/MMBtu
July 2013 — December 2013	Natural Gas	(22,666) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	\$4.50/MMBtu
January 2014 — December 2014	Natural Gas	(21,422) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	\$4.50/MMBtu
January 2015 — December 2015	Natural Gas	(24,738) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	\$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(16,163) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	\$4.50/MMBtu
July 2013 — December 2013	Natural Gas	(3,737) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	\$4.50/MMBtu
January 2014 — December 2014	Natural Gas	(6,766) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	\$4.50/MMBtu
January 2015 — March 2016	Natural Gas	(8,677) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	\$4.50/MMBtu
January 2016 — December 2016	Natural Gas	(4,041) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	\$4.50/MMBtu
July 2013 — December 2013	NGL's	(12,784) Bbls/d	Mt.Belvieu Non-TET (d)	\$.64-2.60/Gal
January 2014 — December 2014	NGL's	(14,334) Bbls/d	Mt.Belvieu Non-TET (d)	\$.64-2.60/Gal
January 2015 — March 2015	NGL's	(16,893) Bbls/d	Mt.Belvieu Non-TET (d)	\$.64-2.60/Gal
July 2015 — December 2015	NGL's	(15,168) Bbls/d	Mt.Belvieu Non-TET (d)	\$.64-1.89/Gal
January 2016 — March 2016	NGL's	(8,937) Bbls/d	Mt.Belvieu Non-TET (d)	\$.64-1.89/Gal
July 2013 — December 2013	Crude Oil	(2,495) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	\$67.60 - \$99.85/Bbl
January 2014 — December 2014	Crude Oil	(1,893) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	\$74.90 - \$96.08/Bbl
January 2015 — December 2015	Crude Oil	(2,043) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	\$87.60-\$100.04/Bbl
January 2016 — March 2016	Crude Oil	(642) Bbls/d		\$95.00-\$101.30/Bbl



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July 2016 — December 2016	Crude Oil	(500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	\$101.30/Bbl
January 2014 — December 2014	Natural Gas	5,000 MMBtu/d	NYMEX Final Settlement Price (g)	\$3.93 - \$4.02/MMBtu
January 2015 — December 2015	Natural Gas	7,500 MMBtu/d	NYMEX Final Settlement Price (g)	\$4.15 - \$4.22/MMBtu
July 2013 — December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	\$4.93/MMBtu
July 2013 — December 2013	Natural Gas	2,000 MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	\$4.52/MMBtu

(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 Inside FERC monthly published index price for Houston Ship Channel.

(f) The inside FERC monthly published index price for Henry Hub.

(g) NYMEX final settlement price for natural gas futures contracts (NG).

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## Commodity Collar Arrangements

Period	Commodity	Notional Volume	Reference Price	Collar Price Range
July 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 2013 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 2013, 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	\$0.10	MMBtu	\$—
Crude oil prices (a)	\$1.00	Barrel	\$—
NGL to crude oil price relationship (b)	1 percentage point change	Barrel	\$1

(a) Assuming 45% NGL to crude oil price relationship. At crude oil prices outside of our collar range of approximately \$80.00 to \$96.50, this sensitivity decreases by less than \$1 million.

Assuming 45% NGL to crude oil price relationship and \$90.00 /Bbl crude oil price. Generally, this sensitivity changes by less than \$1 million for each \$10.00/Bbl change in the price of crude oil. As crude oil prices increase (b) 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.

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We estimate the following non-cash sensitivities 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	\$0.10	MMBtu	\$2
Crude oil prices	\$1.00	Barrel	\$2
NGL prices	\$0.01	Gallon	\$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 substantial 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.

Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices, however there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. The relationship of NGLs to crude oil continues to be lower than historical relationships, however a significant amount of our NGL hedges in 2013 through 2016 are direct product hedges. 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.

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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 June 30, 2013:

## Inventory

Period	Commodity	Notional Volume - Long Positions	Fair Value  (millions)	Weighted Average Price
June 30, 2013	Natural Gas	5,109,649 MMBtu	\$19	\$3.64/MMBtu

## Commodity Swaps

Period	Commodity	Notional Volume -(Short)/Long Positions	Fair Value  (millions)	Price Range
July 2013-October 2014	Natural Gas	(40,257,500) MMBtu	\$7	\$3.41-\$4.28/MMBtu
July 2013-October 2014	Natural Gas	34,092,500 MMBtu	\$(3	) \$3.44-\$4.19/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 June 30, 2013, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of June 30, 2013, 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 June 30, 2013 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## PART II. OTHER INFORMATION

Item 1. Legal Proceedings

There were no material developments during the quarter with respect to the legal proceedings previously disclosed in "Commitments and Contingent Liabilities," included in Note 16 in Item 8. "Financial Statements" included as Exhibit 99.3 to our Current Report on Form 8-K filed on June 14, 2013, and in Note 12 in Item 1 of this Quarterly Report on Form 10-Q.

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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 2012 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 2012 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 consolidated results of operations, financial condition and cash flows.

Our common units may experience price volatility.

Our common unit price has experienced volatility in the past, and volatility in the price of our common units may occur in the future as a result of any of the risk factors contained in our 2012 Form 10-K and the risks described in our other public filings with the SEC. For instance, our common units may experience price volatility as a result of changes in investor sentiment with respect to our competitors, our business partners and our industry in general, which may be influenced by volatility in prices for NGLs, natural gas and crude oil. In addition, the securities markets have from time to time experienced significant price and volume fluctuations that are unrelated to the operating performance of particular companies but affect the market price of their securities. These market fluctuations may also materially and adversely affect the market price of our common units.

Our business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions.

We face cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable. Cybersecurity threats are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.



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Item 6. Exhibits

Exhibit Number	Description
2.1	* Purchase and Sale Agreement (LaSalle Plant) by and between DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (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 August 6, 2013).
2.2	* Purchase and Sale Agreement (Front Range Pipeline) by and among DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
3.1	* Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005, as amended by Amendment No. 1 dated January 20, 2009 (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).
3.2	* Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated February 14, 2013 (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 February 21, 2013).
3.3	* First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP dated December 7, 2005 (attached as Exhibit 3.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
3.4	* Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated November 1, 2006 (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).
3.5	* Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated 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 Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 1, 2009 (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).
10.1	* First Amendment to Services Agreement by and between DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (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 August 6, 2013).
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 six months ended June 30, 2013, 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.



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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on August 6, 2013.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP  
its General Partner

By: DCP Midstream GP, LLC  
its General Partner

By: /s/ Wouter T. van Kempen  
Name: Wouter T. van Kempen  
Title: Chief Executive Officer  
(Principal Executive Officer)

By: /s/ Rose M. Robeson  
Name: Rose M. Robeson  
Senior Vice President and Chief  
Title: Financial Officer (Principal  
Financial Officer)

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## EXHIBIT INDEX

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