DCP Midstream Partners, LP
Form 10-Q
November 06, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 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 (State or other jurisdiction of incorporation or organization)	03-0567133 (I.R.S. Employer Identification No.)
370 17th Street, Suite 2500 Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý 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 ý 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 ý	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨

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

As of November 1, 2013, there were outstanding 87,205,709 common units representing limited partner interests.

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GLOSSARY OF TERMS

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

Bbl	barrel
Bbls/d	barrels per day
Bcf	one billion cubic feet
Bcf/d	one billion cubic feet per day
Btu	British thermal unit, a measurement of energy
Fractionation	the process by which natural gas liquids are separated into individual components
MBbls	one thousand barrels
MBbls/d	one thousand barrels per day
MMBtu	one million Btus
MMBtu/d	one million Btus per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGLs	natural gas liquids
Throughput	the volume of product transported or passing through a pipeline or other facility

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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,” “es “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, in our Annual Report on Form 10-K for the year ended December 31, 2012, or our 2012 Form 10-K, and subsequent filings on Form 10-Q including 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;
- the amount of collateral we may be required to post from time to time in our transactions;
- our ability to execute our asset integrity program to continue the safe and reliable operation of our assets; and
- our ability to hire as well as retain qualified personnel to execute our business strategy.

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)

	September 30, 2013	December 31, 2012
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$1	$2
Accounts receivable:		
Trade, net of allowance for doubtful accounts of less than $1 million	93	107
Affiliates	184	132
Inventories	54	76
Unrealized gains on derivative instruments	85	49
Other	3	2
Total current assets	420	368
Property, plant and equipment, net	2,960	2,550
Goodwill	154	154
Intangible assets, net	131	137
Investments in unconsolidated affiliates	532	304
Unrealized gains on derivative instruments	112	70
Other long-term assets	22	20
Total assets	$4,331	$3,603
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$197	$151
Affiliates	31	72
Unrealized losses on derivative instruments	22	31
Accrued interest	18	8
Accrued taxes	20	5
Capital spending accrual	33	44
Other	37	34
Total current liabilities	358	345
Long-term debt	1,801	1,620
Unrealized losses on derivative instruments	3	8
Other long-term liabilities	36	36
Total liabilities	2,198	2,009
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	357
Limited partners (87,205,709 and 61,346,058 common units issued and outstanding, respectively)	1,915	1,063
General partner	7	—
Accumulated other comprehensive loss	(12)	(15)
Total partners' equity	1,910	1,405
Noncontrolling interests	223	189

Total equity	2,133	1,594
Total liabilities and equity	$4,331	$3,603

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$181	$171	$689	$603
Sales of natural gas, propane, NGLs and condensate to affiliates	460	398	1,263	1,299
Transportation, processing and other	52	46	148	127
Transportation, processing and other to affiliates	11	9	39	30
(Losses) gains from commodity derivative activity, net	(8)	(11)	(6)	17
(Losses) gains from commodity derivative activity, net — affiliates	(24)	(9)	45	33
Total operating revenues	672	604	2,178	2,109
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	527	468	1,585	1,374
Purchases of natural gas, propane and NGLs from affiliates	40	35	141	315
Operating and maintenance expense	56	53	152	145
Depreciation and amortization expense	25	19	68	68
General and administrative expense	4	4	14	12
General and administrative expense — affiliates	11	16	33	44
Other (income) expense	(1)	—	3	—
Total operating costs and expenses	662	595	1,996	1,958
Operating income	10	9	182	151
Interest expense	(14)	(8)	(40)	(32)
Earnings from unconsolidated affiliates	7	9	23	17
Income before income taxes	3	10	165	136
Income tax expense	(1)	—	(2)	(1)
Net income	2	10	163	135
Net income attributable to noncontrolling interests	(3)	(2)	(10)	(8)
Net (loss) income attributable to partners	(1)	8	153	127
Net income attributable to predecessor operations	—	(7)	(6)	(27)
General partner’s interest in net income	(19)	(11)	(50)	(29)
Net (loss) income allocable to limited partners	$(20)	$(10)	$97	$71
Net (loss) income per limited partner unit — basic	$(0.24)	$(0.16)	$1.29	$1.37
Net (loss) income per limited partner unit — diluted	(0.24)	(0.16)	1.29	1.36
Weighted-average limited partner units outstanding — basic	83.0	58.7	75.2	52.5
Weighted-average limited partner units outstanding — diluted	83.0	58.7	75.2	52.6

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Net income	$2	$10	$163	$135
Other comprehensive income:				
Reclassification of cash flow hedge losses into earnings	1	—	3	9
Net unrealized gains (losses) on cash flow hedges	—	1	—	(1)
Total other comprehensive income	1	1	3	8
Total comprehensive income	3	11	166	143
Total comprehensive income attributable to noncontrolling interests	(3)	(2)	(10)	(8)
Total comprehensive income attributable to partners	$—	$9	$156	$135

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2013	2012
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$163	$135
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	68	68
Earnings from unconsolidated affiliates	(23)	(17)
Distributions from unconsolidated affiliates	32	16
Net unrealized losses (gains) on derivative instruments	1	(19)
Other, net	8	1
Change in operating assets and liabilities, which (used) provided cash net of effects of acquisitions:		
Accounts receivable	(25)	81
Inventories	22	17
Accounts payable	(1)	(148)
Accrued interest	10	12
Other current assets and liabilities	10	13
Other long-term assets and liabilities	(1)	(7)
Net cash provided by operating activities	264	152
INVESTING ACTIVITIES:		
Capital expenditures	(277)	(366)
Acquisitions, net of cash acquired	(696)	(375)
Acquisition of unconsolidated affiliates	(86)	(30)
Investments in unconsolidated affiliates	(150)	(86)
Return of investment from unconsolidated affiliate	—	1
Proceeds from sales of assets	—	1
Net cash used in investing activities	(1,209)	(855)
FINANCING ACTIVITIES:		
Proceeds from debt	1,826	1,353
Payments of debt	(1,646)	(1,062)
Payments of deferred financing costs	(4)	(4)
Excess purchase price over acquired interests and commodity hedges	(86)	(110)
Proceeds from issuance of common units, net of offering costs	995	445
Net change in advances to predecessor from DCP Midstream, LLC	32	164
Net change in advances to predecessor – noncontrolling interest	—	44
Distributions to limited partners and general partner	(195)	(128)
Distributions to noncontrolling interests	(16)	(5)
Contributions from noncontrolling interests	40	—
Distributions to DCP Midstream, LLC	(3)	—
Contributions from DCP Midstream, LLC	1	7
Net cash provided by financing activities	944	704
Net change in cash and cash equivalents	(1)	1
Cash and cash equivalents, beginning of period	2	8

Cash and cash equivalents, end of period	$1	$9

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					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2013	$357	$ 1,063	$—	$ (15)	$ 189	$1,594
Net income	6	97	50	—	10	163
Other comprehensive income	—	—	—	3	—	3
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	—	(204)	—	—	—	(204)
Issuance of 23,058,547 common units	—	995	—	—	—	995
Distributions to limited partners and general partner	—	(152)	(43)	—	—	(195)
Distributions to noncontrolling interests	—	—	—	—	(16)	(16)
Contributions from noncontrolling interests	—	—	—	—	40	40
Contributions from DCP Midstream, LLC	—	1	—	—	—	1
Distributions to DCP Midstream, LLC	—	(3)	—	—	—	(3)
Balance, September 30, 2013	$—	$ 1,915	$7	$ (12)	$ 223	$2,133

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					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2012	$628	$ 654	$(5)	$ (21)	$ 306	$1,562
Net income	27	71	29	—	8	135
Other comprehensive (loss) income	(1)	—	—	9	—	8
Net change in parent advances	164	—	—	—	44	208
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
Issuance of units for Mont Belvieu fractionators	—	60	—	—	—	60
Excess purchase price over carrying value of acquired minority ownership interests in Mont Belvieu fractionators	—	(170)	—	—	—	(170)
Deficit purchase price under carrying value of acquired net assets	—	36	—	(4)	—	32
Issuance of 11,031,691 common units	—	445	—	—	—	445
Equity-based compensation	—	(1)	—	—	—	(1)
Distributions to limited partners and general partner	—	(103)	(25)	—	—	(128)
Distributions to noncontrolling interests	—	—	—	—	(5)	(5)
Contributions from DCP Midstream, LLC	—	10	—	—	—	10

Balance, September 30, 2012	$570	$ 1,123	$(1)	$ (16)	$ 177	$1,853

See accompanying notes to condensed consolidated financial statements.

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

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we, 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 80% interest in the Eagle Ford system, of which 33.33% and 46.67% were acquired in November 2012 and March 2013, respectively, our wholly-owned Eagle Plant; our East Texas system; our Southeast Texas system; our Michigan system; our Northern Louisiana system; our Southern Oklahoma system; our Wyoming system; a 75% interest in Collbran Valley Gas Gathering, LLC, or Collbran or our Colorado system; our 40% interest in Discovery Producer Services LLC, or Discovery, and our O'Connor plant), our NGL logistics segment (which includes the NGL storage facility in Michigan, our 12.5% interest in the Mont Belvieu Enterprise fractionator, our 20% interest in the Mont Belvieu 1 fractionator, the Black Lake and Wattenberg interstate NGL pipelines, the DJ Basin NGL fractionators, the Seabreeze and Wilbreeze intrastate NGL pipelines, our 33.33% interest in the Front Range interstate NGL pipeline, and our 10% interest in the Texas Express intrastate NGL pipeline), 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 23% 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.

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 nine months ended September 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 August 5, 2013, we entered into a purchase and sale agreement with DCP Midstream, LP, or Midstream LP, a wholly owned subsidiary of DCP Midstream, LLC, pursuant to which the Partnership acquired from Midstream LP all of the membership interests in DCP LaSalle Plant LLC, or the LaSalle Transaction, for consideration of $209 million, subject to certain customary purchase price adjustments. The LaSalle Transaction was financed at closing using borrowings under our revolving credit facility.

DCP LaSalle Plant LLC owns the O'Connor plant, a 110 MMcf/d cryogenic natural gas processing plant in the DJ Basin in Weld County, Colorado with plans to complete an expansion to 160 MMcf/d. Prior to the start of commercial operations in October 2013, the O'Connor plant was known as the LaSalle plant. In connection with the LaSalle Transaction, we also entered into a 15-year fee-based processing agreement with an affiliate of DCP Midstream, LLC pursuant to which such affiliate agreed to pay us (i) a fixed demand charge of 75% of the plant's capacity, and (ii) a throughput fee on all volumes processed for such affiliate at the O'Connor plant. The LaSalle Transaction represents a transfer of assets between entities under common control. The results of the O'Connor plant are included prospectively from the date of contribution in our Natural Gas Services segment.

On August 5, 2013, we entered into a purchase and sale agreement with Midstream LP pursuant to which the Partnership acquired from Midstream LP all of the membership interests in DCP Midstream Front Range LLC, or Front Range, for consideration of $86 million, subject to certain customary purchase price adjustments, or the Front Range Transaction. The Front Range Transaction was financed at closing using borrowings under our revolving credit facility.

Front Range owns a 33.33% equity interest in Front Range Pipeline LLC, a joint venture with affiliates of Enterprise Products Partners L.P., or Enterprise, and Anadarko Petroleum Corporation. The joint venture was formed to construct a new raw NGL mix pipeline that will originate in the DJ Basin and extend approximately 435 miles to Skellytown, Texas, or the Front Range pipeline. With connections to the Mid-America pipeline, and to the Texas Express pipeline, in which the Partnership owns a 10% interest, the Front Range pipeline will provide takeaway capacity and market access to the Gulf Coast for the expanding production of NGLs in the DJ Basin. The Front Range Pipeline will connect to the O'Connor plant as well as third party and DCP Midstream, LLC plants in the DJ Basin. The initial capacity of the Front Range pipeline is expected to be 150 MBbls/d, which could be expanded to 230 MBbls/d with the installation of additional pump stations. Enterprise is the operator of the pipeline and expects the pipeline to be in service in the first quarter of 2014. The Front Range Pipeline currently has transportation agreements in place with affiliates of DCP Midstream, LLC and others. The transportation agreements provide for ship or pay arrangements for the first 10 years for a minimum volume specified in the agreement with the last 5 years under plant dedication arrangements. The Front Range Transaction represents a transfer of assets between entities under common control. The results of Front Range are included prospectively from the date of contribution in our NGL Logistics segment.

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 $204 million excess purchase price over the carrying value of the acquired interest in the Eagle Ford system, as adjusted for customary working capital and other purchase price adjustments, 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

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

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

Three Months Ended September 30, 2012

	DCP Midstream Partners, LP (As previously reported on Form 10-Q filed on 11/7/12) (Millions)	Consolidate Eagle Ford system (a)	Condensed Consolidated DCP Midstream Partners, LP (As currently reported)
Sales of natural gas, propane, NGLs and condensate	$306	$263	$569
Transportation, processing and other	45	10	55
Losses from commodity derivative activity, net	(20)	—	(20)
Total operating revenues	331	273	604
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	268	235	503
Operating and maintenance expense	36	17	53
Depreciation and amortization expense	15	4	19
General and administrative expense	11	9	20
Total operating costs and expenses	330	265	595
Operating income	1	8	9
Interest expense	(8)	—	(8)
Earnings from unconsolidated affiliates	9	—	9
Income before income taxes	2	8	10
Income tax expense	—	—	—
Net income	2	8	10
Net income attributable to noncontrolling interests	(1)	(1)	(2)
Net income attributable to partners	$1	$7	$8

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

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Nine Months Ended September 30, 2012

	DCP Midstream Partners, LP (As previously reported on Form 10-Q filed on 11/7/12) (Millions)	Consolidate Eagle Ford system (a)	Condensed Consolidated DCP Midstream Partners, LP (As currently reported)
Sales of natural gas, propane, NGLs and condensate	$1,089	$813	$1,902
Transportation, processing and other	131	26	157
Gains from commodity derivative activity, net	50	—	50
Total operating revenues	1,270	839	2,109
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	973	716	1,689
Operating and maintenance expense	92	53	145
Depreciation and amortization expense	50	18	68
General and administrative expense	34	22	56
Total operating costs and expenses	1,149	809	1,958
Operating income	121	30	151
Interest expense	(32)	—	(32)
Earnings from unconsolidated affiliates	17	—	17
Income before income taxes	106	30	136
Income tax expense	(1)	—	(1)
Net income	105	30	135
Net income attributable to noncontrolling interests	(2)	(6)	(8)
Net income attributable to partners	$103	$24	$127

(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 periods 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, as amended, 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Services/Omnibus Agreement	$7	$7	$21	$19
Other fees — DCP Midstream, LLC	4	9	12	25
Total — DCP Midstream, LLC	$11	$16	$33	$44

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In addition to the fees paid pursuant to the Services Agreement and Omnibus Agreement, we incurred allocated expenses, including insurance and internal audit fees with DCP Midstream, LLC of less than $1 million and $1 million for the three and nine months ended September 30, 2013, respectively, and less than $1 million for the three and nine months ended September 30, 2012. The Eagle Ford system incurred $4 million and $9 million in general and administrative expenses directly from DCP Midstream, LLC for the three months ended September 30, 2013 and 2012, respectively, and $11 million and $22 million in general and administrative expenses directly from DCP Midstream, LLC for the nine months ended September 30, 2013 and 2012, respectively. For the nine months ended September 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 $1 million for the three months ended September 30, 2012, and $1 million and $6 million for the nine months ended September 30, 2013 and 2012, respectively. DCP Midstream, LLC made capital contributions to Southeast Texas for capital projects of $2 million and $4 million for the three and nine months ended September 30, 2012, respectively. We made a distribution to DCP Midstream, LLC related to capital projects at Southeast Texas of $3 million for the nine months ended September 30, 2013.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$460	$398	$1,263	$1,290
Transportation, processing and other	$11	$9	$39	$27
Purchases of natural gas, propane and NGLs	$22	$21	$94	$97
(Losses) gains from commodity derivative activity, net	$(24)	$(9)	$45	$33
General and administrative expense	$11	$16	$33	$44
ConocoPhillips (a):				
Sales of natural gas, propane, NGLs and condensate	$—	$—	$—	$9
Transportation, processing and other	$—	$—	$—	$3
Purchases of natural gas, propane and NGLs	$—	$—	$—	$67
Spectra Energy:				
Purchases of natural gas, propane and NGLs	$18	$14	$47	$149
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.

We had balances with affiliates as follows:

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	September 30, 2013	December 31, 2012
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$183	$132
Accounts payable	$24	$66
Unrealized gains on derivative instruments — current	$84	$48
Unrealized gains on derivative instruments — long-term	$106	$64
Unrealized losses on derivative instruments — current	$7	$11
Unrealized losses on derivative instruments — long-term	$1	$—
Spectra Energy:		
Accounts receivable	$1	$—
Accounts payable	$7	$5
Unconsolidated affiliates:		
Accounts payable	$—	$1

4. Inventories

Inventories were as follows:

	September 30, 2013	December 31, 2012
	(Millions)	
Natural gas	$26	$22
NGLs	28	54
Total inventories	$54	$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 $1 million and $4 million in lower of cost or market adjustments during the three and nine months ended September 30, 2013, respectively, and less than $1 million and $19 million in lower of cost or market adjustments during the three and nine months ended September 30, 2012, respectively.

5. Property, Plant and Equipment

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

	Depreciable Life	September 30, 2013	December 31, 2012
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$2,126	$1,921
Processing, storage, and terminal facilities	35 — 60 Years	1,342	1,103
Other	3 — 30 Years	34	31
Construction work in progress		586	561
Property, plant and equipment		4,088	3,616
Accumulated depreciation		(1,128)	(1,066)
Property, plant and equipment, net		$2,960	$2,550

Interest capitalized on construction projects for the three months ended September 30, 2013 and 2012 was $4 million and $2 million, respectively, and for the nine months ended September 30, 2013 and 2012 was $7 million and $5 million, respectively.

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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 and $34 million reduction in depreciation expense for the three and nine months ended September 30, 2012, respectively, which increased net income per limited partner unit by $0.29 and $0.65, respectively.

Depreciation expense was $23 million and $17 million for the three months ended September 30, 2013 and 2012, respectively, and $62 million for each of the nine months ended September 30, 2013 and 2012.

During the nine months ended September 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. Goodwill

The carrying value of goodwill as of September 30, 2013 and December 31, 2012 was $82 million for each of the periods for our Natural Gas Services segment, $35 million for each of the periods for our NGL Logistics segment, and $37 million for each of the periods for our Wholesale Propane Logistics segment.

We performed our annual goodwill assessment during the quarter at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the entire amount of goodwill disclosed on the condensed consolidated balance sheet is recoverable. We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

7. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of September 30, 2013	December 31, 2012
		(Millions)	
Discovery Producer Services LLC	40%	$283	$223
Front Range Pipeline LLC	33.33%	112	—
Texas Express Pipeline	10%	92	41
Mont Belvieu Enterprise Fractionator	12.5%	22	19
Mont Belvieu 1 Fractionator	20%	16	14
CrossPoint Pipeline, LLC	50%	6	6
Other	Various	1	1
Total investments in unconsolidated affiliates		$532	$304

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $28 million and $30 million at September 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.

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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 September 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 Texas Express of $3 million and less than $1 million at September 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 once placed into service.

There was an excess of the carrying amount of the investment over the underlying equity of Front Range of $3 million at September 30, 2013, 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 Front Range Pipeline once placed into service.

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Discovery Producer Services LLC	$(1)	$4	$—	$12
Mont Belvieu Enterprise Fractionator	3	3	9	3
Mont Belvieu 1 Fractionator	5	2	14	2
Total earnings from unconsolidated affiliates	$7	$9	$23	$17

The following tables summarize the combined financial information of our investments in unconsolidated affiliates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Statements of operations:				
Operating revenue	$109	$91	$340	$174
Operating expenses	$71	$49	$210	$115
Net income	$33	$42	$125	$58

	September 30, 2013	December 31, 2012
	(Millions)	
Balance sheets:		
Current assets	$172	$129
Long-term assets	2,300	1,288
Current liabilities	(176)	(75)
Long-term liabilities	(46)	(43)
Net assets	$2,250	$1,299

8. Fair Value Measurement

Determination of Fair Value

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

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

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 10 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.

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Commodity Derivative Assets and Liabilities

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

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

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

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

Interest Rate Derivative Assets and Liabilities

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

Nonfinancial Assets and Liabilities

We utilize fair value 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.

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

	September 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets (a):								
Commodity derivatives	$—	$10	$75	$85	$—	$9	$40	$49
Long-term assets (b):								
Commodity derivatives	$—	$9	$103	$112	$—	$5	$65	$70
Current liabilities (c):								
Commodity derivatives	$—	$(18)	$(1)	$(19)	$—	$(26)	$(1)	$(27)
Interest rate derivatives	$—	$(3)	$—	$(3)	$—	$(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 nine months ended September 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. 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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	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended September 30, 2013 (a):				
Beginning balance	$87	$138	$—	$—
Net realized and unrealized gains (losses) included in earnings (c)	9	(33)	(1)	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(3)	(2)	—	—
Settlements	(18)	—	—	—
Ending balance	$75	$103	$(1)	$—
Net unrealized gains (losses) still held included in earnings (c)	$24	$(33)	$(21)	$—
Three months ended September 30, 2012 (a):				
Beginning balance	$44	$35	$(1)	$—
Net realized and unrealized (losses) gains included in earnings (c)	(2)	(6)	1	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(14)	—	—	—
Settlements	(7)	—	—	—
Ending balance	$21	$29	$—	$—
Net unrealized gains (losses) still held included in earnings (c)	$3	$(6)	$—	$—

(a) There were no purchases, issuances and sales of derivatives for the three months ended September 30, 2013 and 2012.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) 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.

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	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Nine months ended September 30, 2013 (a):				
Beginning balance	$40	$65	$(1)	$—
Net realized and unrealized gains (losses) included in earnings (c)	45	(22)	—	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(3)	(2)	—	—
Settlements	(31)	—	—	—
Purchases	24	62	—	—
Ending balance	$75	$103	$(1)	$—
Net unrealized gains (losses) still held included in earnings (c)	$84	$40	$(28)	$—
Nine months ended September 30, 2012 (a):				
Beginning balance	$1	$1	$(1)	$—
Net realized and unrealized gains included in earnings (c)	9	1	1	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(2)	—	1	—
Purchases	13	27	(1)	—
Ending balance	$21	$29	$—	$—
Net unrealized gains still held included in earnings (c)	$8	$2	$1	$—

(a) There were no issuances and sales of derivatives for the nine months ended September 30, 2013 and 2012.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) 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.

	September 30, 2013		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$171	$0.25-$2.07	Per gallon
Natural Gas	$7	$3.69-$4.34	Per MMBtu
Liabilities			

Natural Gas	$(1)	$3.89-$4.04	Per MMBtu

Estimated Fair Value of Financial Instruments

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

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

The fair value of our interest rate swaps and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, our 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 was $211 million as of September 30, 2013 and $525 million as of December 31, 2012, which approximated fair value at each date. The carrying and fair values of the 3.875% Senior Notes were $494 million and $455 million, respectively, as of September 30, 2013. The carrying value of the 2.50% Senior Notes was $497 million as of September 30, 2013 and December 31, 2012, which approximated fair value at each date. The carrying value of the 4.95% Senior Notes was $349 million as of September 30, 2013, which approximated fair value. The carrying and fair values of the 4.95% Senior Notes were $348 million and $374 million, respectively, as of December 31, 2012. The carrying and fair values of the 3.25% Senior Notes were $250 million and $258 million, respectively, as of September 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.

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9. Debt

Long-term debt was as follows:

	September 30, 2013	December 31, 2012
	(Millions)	
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 1.44% and 1.47%, respectively, due November 10, 2016 (a)	$211	$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	$1,801	$1,620

(a) $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 3.41% on the $211 million of outstanding debt under our revolving credit facility as of September 30, 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 September 30, 2013 and December 31, 2012, we had $1 million of letters of credit issued and outstanding under the Credit Agreement. As of September 30, 2013, the unused capacity under the Credit Agreement was $788 million, all of which was available for general working capital purposes.

Our borrowing capacity may be limited 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.

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

	Debt Maturities (Millions)
2014	$—
2015	250
2016	211
2017	500
Thereafter	850
	1,811
Unamortized discount	(10)
Total	$1,801

10. 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 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. During the third quarter of 2013, Southeast Texas began purchasing base gas to bring the storage cavern to operation. To mitigate risk associated with the forecasted purchase of natural gas, we executed a series of derivative financial instruments, which were designated as cash flow hedges. The balance in accumulated other comprehensive income, or AOCI, of these cash flow hedges was in a loss position of $3 million as of September 30, 2013. While the cash paid upon settlement of these hedges economically fixed the cash required to purchase the base gas, the deferred loss 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 September 30, 2013, we had interest rate swap agreements extending through June 2014 totaling $150 million, which are accounted for under the mark-to-market method of accounting and 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. Prior to August of 2013, these interest rate swaps were designated as cash flow hedges whereby the effective portions of changes in fair value were recognized in AOCI in the condensed consolidated balance sheets. The deferred loss of $3 million in AOCI will be reclassified into earnings as the hedged transactions impact earnings.

In March 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.

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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 September 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 September 30, 2013, we had $13 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 September 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 September 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 September 30, 2013, we had $150 million of interest rate swap instruments that were in a net liability position of $3 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.

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

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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:

	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount
	September 30, 2013			December 31, 2012		
Assets:						
Commodity derivatives	$197	$ (9)	$188	$119	$ (10)	$109
Interest rate derivatives	$—	$ —	$—	$—	$ —	$—
Liabilities:						
Commodity derivatives	$(22)	$ 9	$(13)	$(33)	$ 10	$(23)
Interest rate derivatives	$(3)	$ —	$(3)	$(6)	$ —	$(6)

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

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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	September 30, 2013	December 31, 2012	Balance Sheet Line Item	September 30, 2013	December 31, 2012
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			Derivative Liabilities Designated as Hedging Instruments:		
Commodity derivatives:			Commodity derivatives:		
Unrealized gains on derivative instruments — current	$—	$—	Unrealized losses on derivative instruments — current	$—	$(3)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	$—	$—		$—	$(3)
Interest rate derivatives:			Interest rate derivatives:		
Unrealized gains on derivative instruments — current	$—	$—	Unrealized losses on derivative instruments — current	$—	$(4)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	(2)
	$—	$—		$—	$(6)
Derivative Assets Not Designated as Hedging Instruments:			Derivative Liabilities Not Designated as Hedging Instruments:		
Commodity derivatives:			Commodity derivatives:		
Unrealized gains on derivative instruments — current	$85	$49	Unrealized losses on derivative instruments — current	$(19)	$(24)
Unrealized gains on derivative instruments — long-term	112	70	Unrealized losses on derivative instruments — long-term	(3)	(6)
	$197	$119		$(22)	$(30)
Interest rate derivatives:			Interest rate derivatives:		
Unrealized gains on derivative instruments — current	$—	$—	Unrealized losses on derivative instruments — current	$(3)	$—
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	$—	$—		$(3)	$—

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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 September 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)	$(8)		$(5)	$—	$(13)
Gains (losses) recognized in AOCI on derivatives — effective portion	—		(1)	1	—
Losses reclassified from AOCI to earnings — effective portion	1	(b)	—	—	1
Net deferred losses in AOCI (ending balance)	$(7)		$(6)	$1	$(12)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$(3)		$—	$—	$(3)

(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 nine months ended September 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	—		—	—	—
Losses reclassified from AOCI to earnings — effective portion	3	(b)	—	—	3
Net deferred losses in AOCI (ending balance)	$(7)		$(6)	$1	$(12)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$(3)		$—	$—	$(3)

(a) Relates to Discovery, our unconsolidated affiliate.
(b) Included in interest expense in our condensed consolidated statements of operations.

For both the three and nine months ended September 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 nine months ended September 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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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 September 30, 2012:

	(Losses) Gains 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	$(1)	$— (a)	$—
Commodity derivatives	$1	$—	$—
Foreign currency derivatives (b)	$1	$—	$—

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) Relates to Discovery, our unconsolidated affiliate.
(c) For the three months ended September 30, 2012, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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 nine months ended September 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	$(1)	$(9) (a)	$ (2) (a) (b)
Commodity derivatives	$—	$—	$ —
Foreign currency derivatives (c)	$—	$—	$ —

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) For the nine months ended September 30, 2012, $1 million of derivative losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.
(c) Relates to Discovery, our unconsolidated affiliate.

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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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Third party:				
Realized (losses) gains	$(7)	$(4)	$(14)	$7
Unrealized (losses) gains	(1)	(7)	8	10
(Losses) gains from commodity derivative activity, net	$(8)	$(11)	$(6)	$17
Affiliates:				
Realized gains	$25	$7	$55	$24
Unrealized (losses) gains	(49)	(16)	(10)	9
(Losses) gains from commodity derivative activity, net —affiliates	$(24)	$(9)	$45	$33

Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Third party:				
Realized losses	$—	$(1)	$(1)	$(7)
Unrealized gains	—	1	1	7
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.

	September 30, 2013			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long Position (MMbtu)
2013	(259,596)	(6,890,076)	(1,231,128)	3,532,500
2014	(690,945)	(11,446,120)	(5,186,910)	13,275,000
2015	(745,695)	(9,458,975)	(5,691,570)	3,650,000
2016	(561,922)	(1,838,564)	(813,267)	—

	September 30, 2012			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps

Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long (Short) Position (Mmbtu)
2012	(170,759)	(240,000)	(788,429)	605,000
2013	(927,310)	(6,865,000)	(700,975)	10,072,500
2014	(547,500)	(365,000)	(629,625)	(900,000)
2015	(365,000)	—	(155,250)	—
2016	(183,000)	—	—	—

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We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of September 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.

11. 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.

In August 2013, we issued 9,000,000 common units at $50.04 per unit. We received proceeds of $434 million, net of offering costs.

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 September 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 nine months ended September 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 offering costs of $2 million, which were used to finance growth opportunities and for general corporate purposes. As of September 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)
August 14, 2013	$0.71	$72
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

12. 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 potentially dilutive effect of unit-based awards was 18,074 and 26,466 equivalent units during the three months ended September 30, 2013 and 2012, respectively. The dilutive effect of unit-based awards was 21,175 and 35,908 equivalent units during the nine months ended September 30, 2013 and 2012, respectively.

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

13. Commitments and Contingent Liabilities

Prospect — During the fourth quarter of 2011, we received a claim for arbitration, or the Claim, filed with the American Arbitration Association by Prospect Street Energy, LLC and Prospect Street Ventures I, LLC, or together, the Claimants, against EE Group, LLC, or EE Group, and a number of other parties that previously owned, directly or indirectly, our Marysville NGL storage facility, or collectively, the Respondents. EE Group is our indirect subsidiary which we acquired in connection with our acquisition of Marysville Hydrocarbons Holdings, LLC, or Marysville, on December 30, 2010, or 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.

Insurance - We renewed our insurance policies in May, June and July 2013 for the 2013-2014 insurance year. We contract with third party and affiliate insurers for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) general liability insurance; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of real and personal property and includes business interruption/extra expense. These renewals have not resulted in any material change to the premiums we are contracted to pay or our limits in the 2013-2014 insurance year compared with the 2012-2013 insurance year. We are jointly insured with DCP Midstream, LLC for a portion of the directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

The insurance on Discovery, as placed by Williams Field Service Group LLC, for the 2013-2014 insurance year includes general and excess liability, onshore property damage, including named windstorm and business interruption, and offshore non-wind property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past few years as a result of higher industry-wide damage claims. Additionally, the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, higher deductibles and lower coverage limits. As such, Discovery continues to elect not to purchase offshore named windstorm property and business interruption insurance coverage for the 2013-2014 insurance year.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities 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.

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

14. 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 80% interest in the Eagle Ford system, our wholly-owned Eagle Plant, our East Texas system, our Southeast Texas system, our Michigan system, our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our 75% interest in the Colorado system, our 40% interest in Discovery, and our O'Connor plant.
NGL Logistics — Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of the NGL storage facility in Michigan, our 20% interest in the Mont Belvieu 1 fractionator, our 12.5% interest in the Mont Belvieu Enterprise fractionator, the Black Lake and Wattenberg interstate NGL pipelines, the DJ Basin NGL fractionators in Colorado, the Seabreeze and Wilbreeze intrastate NGL pipelines, our 33.33% interest in the Front Range interstate NGL pipeline, and our 10% interest in the Texas Express intrastate NGL pipeline.
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.
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 September 30, 2013

	Natural Gas Services	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	$608	$17	$47	$—	$672
Total purchases	(524)	—	(43)	—	(567)
Gross margin (a)	$84	$17	$4	—	$105
Operating and maintenance expense	(47)	(5)	(4)	—	(56)
Depreciation and amortization expense	(22)	(2)	(1)	—	(25)
General and administrative expense	—	—	—	(15)	(15)
Other income	—	1	—	—	1
(Loss) earnings from unconsolidated affiliates	(1)	8	—	—	7
Interest expense	—	—	—	(14)	(14)
Income tax expense	—	—	—	(1)	(1)
Net income (loss)	$14	$19	$(1)	$(30)	$2
Net income attributable to noncontrolling interests	(3)	—	—	—	(3)
Net income (loss) attributable to partners	$11	$19	$(1)	$(30)	$(1)
Non-cash derivative mark-to-market (b)	$(49)	$—	$(1)	$1	$(49)
Non-cash lower of cost or market adjustments	$—	$—	$1	$—	$1

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

Three Months Ended September 30, 2012

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	$551	$16	$37	$—	$604
Total purchases	(468)	—	(35)	—	(503)
Gross margin (a)	$83	$16	$2	$—	$101
Operating and maintenance expense	(44)	(5)	(4)	—	(53)
Depreciation and amortization expense	(16)	(2)	(1)	—	(19)
General and administrative expense	—	—	—	(20)	(20)
Earnings from unconsolidated affiliates	4	5	—	—	9
Interest expense	—	—	—	(8)	(8)
Net income (loss)	$27	$14	$(3)	$(28)	$10
Net income attributable to noncontrolling interests	(2)	—	—	—	(2)
Net income (loss) attributable to partners	$25	$14	$(3)	$(28)	$8
Non-cash derivative mark-to-market (b)	$(21)	$—	$(2)	$1	$(22)

Nine Months Ended September 30, 2013

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	$1,868	$55	$255	$—	$2,178
Total purchases	(1,508)	—	(218)	—	(1,726)
Gross margin (a)	$360	$55	$37	—	$452
Operating and maintenance expense	(128)	(13)	(11)	—	(152)
Depreciation and amortization expense	(61)	(5)	(2)	—	(68)
General and administrative expense	—	—	—	(47)	(47)
Other income (expense)	—	1	(4)	—	(3)
Earnings from unconsolidated affiliates	—	23	—	—	23
Interest expense	—	—	—	(40)	(40)
Income tax expense	—	—	—	(2)	(2)
Net income (loss)	$171	$61	$20	$(89)	$163
Net income attributable to noncontrolling interests	(10)	—	—	—	(10)
Net income (loss) attributable to partners	$161	$61	$20	$(89)	$153
Non-cash derivative mark-to-market (b)	$—	$—	$(2)	$1	$(1)
Non-cash lower of cost or market adjustments	$2	$—	$2	$—	$4
Capital expenditures	$260	$15	$2	$—	$277
Acquisition expenditures	$696	$86	$—	$—	$782
Investments in unconsolidated affiliates	$67	$83	$—	$—	$150

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

Nine Months Ended September 30, 2012

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	$1,748	$47	$314	$—	$2,109
Total purchases	(1,399)	—	(290)	—	(1,689)
Gross margin (a)	$349	$47	$24	$—	$420
Operating and maintenance expense	(121)	(13)	(11)	—	(145)
Depreciation and amortization expense	(61)	(5)	(2)	—	(68)
General and administrative expense	—	—	—	(56)	(56)
Other income	—	—	—	—	—
Earnings from unconsolidated affiliates	12	5	—	—	17
Interest expense	—	—	—	(32)	(32)
Income tax expense	—	—	—	(1)	(1)
Net income (loss)	$179	$34	$11	$(89)	$135
Net income attributable to noncontrolling interests	(8)	—	—	—	(8)
Net income (loss) attributable to partners	$171	$34	$11	$(89)	$127
Non-cash derivative mark-to-market (b)	$5	$—	$14	$—	$19
Non-cash lower of cost or market adjustments	$4	$—	$15	$—	$19
Capital expenditures	$354	$9	$3	$—	$366
Acquisition expenditures	$375	$30	$—	$—	$405
Investments in unconsolidated affiliates	$53	$33	$—	$—	$86

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

	September 30, 2013	December 31, 2012
	(Millions)	
Segment long-term assets:		
Natural Gas Services (c)	$3,161	$2,706
NGL Logistics	517	340
Wholesale Propane Logistics	104	105
Other (d)	129	84
Total long-term assets	3,911	3,235
Current assets (c)	420	368
Total assets	$4,331	$3,603

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

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

(c) The segment information for the nine months ended September 30, 2013, three and nine months ended September 30, 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 nine months ended September 30, 2012, includes the results of our 100% interest in Southeast Texas. Transfers of net assets between entities under common control 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.

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

15. Supplemental Cash Flow Information

	Nine Months Ended September 30, 2013	2012
	(Millions)	
Cash paid for interest and income taxes:		
Cash paid for interest, net of amounts capitalized	$25	$7
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	$41	$27
Other non-cash additions of property, plant and equipment	$1	$7
Non-cash contributions from DCP Midstream, LLC	$—	$3

16. 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 Condensed Consolidating Balance Sheet September 30, 2013				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$—	$—	$ 1	$—	$ 1
Accounts receivable, net	—	—	277	—	277
Inventories	—	—	54	—	54
Other	—	—	88	—	88
Total current assets	—	—	420	—	420
Property, plant and equipment, net	—	—	2,960	—	2,960
Goodwill and intangible assets, net	—	—	285	—	285
Advances receivable — consolidated subsidiaries	1,799	1,576	—	(3,375)	—
Investments in consolidated subsidiaries	111	344	—	(455)	—
Investments in unconsolidated affiliates	—	—	532	—	532
Other long-term assets	—	13	121	—	134
Total assets	$ 1,910	$ 1,933	$ 4,318	$ (3,830)	$ 4,331
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$—	$ 21	$ 337	$—	$ 358
Advances payable — consolidated subsidiaries	—	—	3,375	(3,375)	—
Long-term debt	—	1,801	—	—	1,801
Other long-term liabilities	—	—	39	—	39
Total liabilities	—	1,822	3,751	(3,375)	2,198
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	1,910	118	349	(455)	1,922
Accumulated other comprehensive loss	—	(7)	(5)	—	(12)
Total partners' equity	1,910	111	344	(455)	1,910
Noncontrolling interests	—	—	223	—	223
Total equity	1,910	111	567	(455)	2,133
Total liabilities and equity	$ 1,910	$ 1,933	$ 4,318	$ (3,830)	$ 4,331

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

	Condensed Consolidating Balance Sheet December 31, 2012 (a)				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
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
LIABILITIES AND EQUITY					
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

(a) 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 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 September 30, 2013

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$—	$—	$641	$—	$641
Transportation, processing and other	—	—	63	—	63
Losses from commodity derivative activity, net	—	—	(32)	—	(32)
Total operating revenues	—	—	672	—	672
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	567	—	567
Operating and maintenance expense	—	—	56	—	56
Depreciation and amortization expense	—	—	25	—	25
General and administrative expense	—	—	15	—	15
Other income	—	—	(1)	—	(1)
Total operating costs and expenses	—	—	662	—	662
Operating income	—	—	10	—	10
Interest expense	—	(14)	—	—	(14)
(Loss) income from consolidated subsidiaries	(1)	13	—	(12)	—
Earnings from unconsolidated affiliates	—	—	7	—	7
(Loss) income before income taxes	(1)	(1)	17	(12)	3
Income tax expense	—	—	(1)	—	(1)
Net (loss) income	(1)	(1)	16	(12)	2
Net income attributable to noncontrolling interests	—	—	(3)	—	(3)
Net (loss) income attributable to partners	$(1)	$(1)	$13	$(12)	$(1)

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

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net (loss) income	$(1)	$(1)	$ 16	$(12)	$2
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 (loss)	—	—	16	(13)	3

Total comprehensive income attributable to noncontrolling interests	—	—	(3)	—	(3)
Total comprehensive income (loss)attributable to partners	$—	$—	$ 13	$(13)	$—

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

	Condensed Consolidating Statement of Operations Three Months Ended September 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$—	$—	$ 569	$—	$569
Transportation, processing and other	—	—	55	—	55
Losses from commodity derivative activity, net	—	—	(20)	—	(20)
Total operating revenues	—	—	604	—	604
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	503	—	503
Operating and maintenance expense	—	—	53	—	53
Depreciation and amortization expense	—	—	19	—	19
General and administrative expense	—	—	20	—	20
Total operating costs and expenses	—	—	595	—	595
Operating income	—	—	9	—	9
Interest expense	—	(9)	1	—	(8)
Income from consolidated subsidiaries	8	17	—	(25)	—
Earnings from unconsolidated affiliates	—	—	9	—	9
Income before income taxes	8	8	19	(25)	10
Income tax expense	—	—	—	—	—
Net income	8	8	19	(25)	10
Net income attributable to noncontrolling interests	—	—	(2)	—	(2)
Net income attributable to partners	$8	$8	$ 17	$(25)	$8

(a) The financial information for the three months ended September 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 September 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$8	$8	$ 19	$(25)	$10
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	—	—	—	—
Net unrealized (losses) gains on cash flow hedges	—	(1)	2	—	1
Other comprehensive income from consolidated subsidiaries	1	2	—	(3)	—
Total other comprehensive income	1	1	2	(3)	1
Total comprehensive income	9	9	21	(28)	11
Total comprehensive income attributable to noncontrolling interests	—	—	(2)	—	(2)
Total comprehensive income attributable to partners	$9	$9	$ 19	$(28)	$9

(a) The financial information for the three months ended September 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 Nine Months Ended September 30, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$—	$—	$1,952	$—	$1,952
Transportation, processing and other	—	—	187	—	187
Gains from commodity derivative activity, net	—	—	39	—	39
Total operating revenues	—	—	2,178	—	2,178
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	1,726	—	1,726
Operating and maintenance expense	—	—	152	—	152
Depreciation and amortization expense	—	—	68	—	68
General and administrative expense	—	—	47	—	47
Other expense	—	—	3	—	3
Total operating costs and expenses	—	—	1,996	—	1,996
Operating income	—	—	182	—	182
Interest expense	—	(40)	—	—	(40)
Income from consolidated subsidiaries	153	193	—	(346)	—
Earnings from unconsolidated affiliates	—	—	23	—	23
Income before income taxes	153	153	205	(346)	165
Income tax expense	—	—	(2)	—	(2)
Net income	153	153	203	(346)	163
Net income attributable to noncontrolling interests	—	—	(10)	—	(10)
Net income attributable to partners	$153	$153	$193	$(346)	$153

(a) The financial information for the nine months ended September 30, 2013 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 Nine Months Ended September 30, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$153	$153	$ 203	$(346)	$163
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	3	—	—	3
Other comprehensive income from consolidated subsidiaries	3	—	—	(3)	—
Total other comprehensive income	3	3	—	(3)	3
Total comprehensive income	156	156	203	(349)	166
Total comprehensive income attributable to noncontrolling interests	—	—	(10)	—	(10)
Total comprehensive income attributable to partners	$156	$156	$ 193	$(349)	$156

(a) The financial information for the nine months ended September 30, 2013 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 Nine Months Ended September 30, 2012 (a)				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$—	$—	$ 1,902	$—	$ 1,902
Transportation, processing and other	—	—	157	—	157
Gains from commodity derivative activity, net	—	—	50	—	50
Total operating revenues	—	—	2,109	—	2,109
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	1,689	—	1,689
Operating and maintenance expense	—	—	145	—	145
Depreciation and amortization expense	—	—	68	—	68
General and administrative expense	—	—	56	—	56
Total operating costs and expenses	—	—	1,958	—	1,958
Operating income	—	—	151	—	151
Interest expense	—	(32)	—	—	(32)
Income from consolidated subsidiaries	127	159	—	(286)	—
Earnings from unconsolidated affiliates	—	—	17	—	17
Income before income taxes	127	127	168	(286)	136
Income tax expense	—	—	(1)	—	(1)
Net income	127	127	167	(286)	135
Net income attributable to noncontrolling interests	—	—	(8)	—	(8)
Net income attributable to partners	$ 127	$ 127	$ 159	$ (286)	$ 127

(a) The financial information for the nine months ended September 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 Comprehensive Income Nine Months Ended September 30, 2012 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$127	$127	$ 167	$(286)	$135
Other comprehensive loss:					
Reclassification of cash flow hedge losses into earnings	—	9	—	—	9
Net unrealized losses on cash flow hedges	—	(1)	—	—	(1)
Other comprehensive income from consolidated subsidiaries	8	—	—	(8)	—
Total other comprehensive income	8	8	—	(8)	8
Total comprehensive income	135	135	167	(294)	143
Total comprehensive income attributable to noncontrolling interests	—	—	(8)	—	(8)
Total comprehensive income attributable to partners	$135	$135	$ 159	$(294)	$135

(a) The financial information for the nine months ended September 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.

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

Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2013 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$(800)	$(179)	$ 1,240	$3	$264
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(277)	—	(277)
Acquisitions, net of cash acquired	—	—	(696)	—	(696)
Acquisition of unconsolidated affiliates	—	—	(86)	—	(86)
Investments in unconsolidated affiliates	—	—	(150)	—	(150)
Net cash used in investing activities	—	—	(1,209)	—	(1,209)
FINANCING ACTIVITIES:					
Proceeds from debt	—	1,826	—	—	1,826
Payments of debt	—	(1,646)	—	—	(1,646)
Payments of deferred financing cost	—	(4)	—	—	(4)
Excess purchase price over acquired interests and commodity hedge	—	—	(86)	—	(86)
Proceeds from issuance of common units, net of offering cost	995	—	—	—	995
Net change in advances to predecessor from DCP Midstream, LLC	—	—	32	—	32
Distributions to limited partners and general partner	(195)	—	—	—	(195)
Distributions to noncontrolling interests	—	—	(16)	—	(16)
Contributions from noncontrolling interests	—	—	40	—	40
Distributions to DCP Midstream, LLC	—	—	(3)	—	(3)
Contributions from DCP Midstream, LLC	—	—	1	—	1
Net cash provided by (used in) financing activities	800	176	(32)	—	944
Net change in cash and cash equivalents	—	(3)	(1)	3	(1)
Cash and cash equivalents, beginning of period	—	3	2	(3)	2
Cash and cash equivalents, end of period	$—	$—	$ 1	$—	$1

(a) The financial information for the nine months ended September 30, 2013 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 Statements of Cash Flows Nine Months Ended September 30, 2012 (a)				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$(317)	$(285)	$751	$3	$152
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(366)	—	(366)
Acquisitions, net of cash acquired	—	—	(375)	—	(375)
Acquisitions of unconsolidated affiliates	—	—	(30)	—	(30)
Investments in unconsolidated affiliates	—	—	(86)	—	(86)
Return of investment in unconsolidated affiliates	—	—	1	—	1
Proceeds from sales of assets	—	—	1	—	1
Net cash used in investing activities	—	—	(855)	—	(855)
FINANCING ACTIVITIES:					
Proceeds from debt	—	1,353	—	—	1,353
Payments of debt	—	(1,062)	—	—	(1,062)
Payment of deferred financing costs	—	(4)	—	—	(4)
Excess purchase price over acquired interests and commodity hedges	—	—	(110)	—	(110)
Proceeds from issuance of common units, net of offering costs	445	—	—	—	445
Distributions to limited partners and general partner	(128)	—	—	—	(128)
Distributions to noncontrolling interests	—	—	(5)	—	(5)
Contributions from DCP Midstream, LLC	—	—	7	—	7
Net change in advances to predecessor from DCP Midstream, LLC	—	—	164	—	164
Net change in advances to predecessor - noncontrolling interest	—	—	44	—	44
Net cash provided by (used in) financing activities	317	287	100	—	704
Net change in cash and cash equivalents	—	2	(4)	3	1
Cash and cash equivalents, beginning of period	—	4	6	(2)	8
Cash and cash equivalents, end of period	$—	$6	$2	$1	$9

(a) The financial information during the nine months ended September 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.

17. Subsequent Events

On October 25, 2013, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.72 per unit, payable on November 14, 2013 to unitholders of record on November 7, 2013.

In October 2013, the Partnership and its wholly-owned subsidiary, DCP Midstream Operating, LP, or the Operating Partnership, entered into a commercial paper program, or the commercial paper program, under which the Operating Partnership may issue unsecured commercial paper notes, or the Notes, guaranteed by the Partnership. The commercial paper program serves as an alternative source of funding for the Operating Partnership and does not increase the Operating Partnership's current overall borrowing capacity. Amounts available under the commercial paper program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of Notes outstanding, combined with the amount outstanding under our revolving credit facility, not to exceed $1 billion in the aggregate. Amounts undrawn under our revolving credit facility, which expires on November 10, 2016, are available to repay the Notes, if necessary. The maturities of the Notes will vary, but may not exceed 397 days from the date of issue. The Notes will be sold under customary terms in the commercial paper market and may be issued at a discount from par, or, alternatively, may be sold at par and bear varying interest rates on a fixed or floating basis. The proceeds of the issuances of the Notes are expected to be used for capital expenditures and other general partnership purposes.

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 and natural gas prices remain modest due to increasing supplies. 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 supporting 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 billion.

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Some of our recent growth projects include the following:

- On August 5, 2013, we entered into a purchase and sale agreement with a wholly owned subsidiary of DCP Midstream, LLC pursuant to which the Partnership acquired all of the membership interests in DCP LaSalle Plant LLC, or the LaSalle Transaction, for consideration of $209 million, subject to certain customary purchase price adjustments. DCP LaSalle Plant LLC owns the O'Connor plant, a 110 MMcf/d cryogenic natural gas processing plant, previously known as the LaSalle plant, in the DJ Basin in Weld County, Colorado with plans to complete an expansion to 160 MMcf/d. In connection with the LaSalle Transaction, we also entered into a 15-year fee-based processing agreement with an affiliate of DCP Midstream, LLC pursuant to which such affiliate agreed to pay us (i) a fixed demand charge of 75% of the plant's capacity, and (ii) a throughput fee on all volumes processed for such affiliate at the O'Connor plant. The processing agreement commenced with commercial operations of the new plant in October 2013.
- On August 5, 2013, we entered into a purchase and sale agreement with a wholly owned subsidiary of DCP Midstream, LLC pursuant to which the Partnership acquired all of the membership interests in DCP Midstream Front Range LLC, or Front Range, for consideration of $86 million, subject to certain customary purchase price adjustments. Front Range owns a 33.33% equity interest in Front Range Pipeline LLC, a joint venture with affiliates of Enterprise and Anadarko Petroleum Corporation, which was formed to construct the Front Range pipeline, a new raw NGL mix pipeline that will originate in the DJ Basin and extend approximately 435 miles to Skellytown, Texas. Enterprise is the operator of the pipeline and expects the Front Range pipeline to be in service in the first quarter of 2014.
- On March 28, 2013, we acquired an additional 46.67% interest in 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 fixed price commodity price hedges, representing a total investment of approximately $290 million, is expected to be in-service in the first quarter of 2014.
- Our expansion plan for Discovery's Keathley Canyon natural gas gathering pipeline system is progressing and is expected to be completed in the fourth quarter of 2014.
- The construction of the Texas Express pipeline, of which we own a 10% interest, is complete and commenced operations in the fourth quarter of 2013. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express pipeline extends approximately 580 miles to Enterprise’s natural gas liquids fractionation and storage complex at Mont Belvieu, Texas, and provides access to other third party facilities in the area.
- Our construction of our wholly-owned Eagle 200 MMcf/d natural gas processing plant is complete and commenced operations in the first quarter of 2013.

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 August 2013, we issued 9,000,000 common units at $50.04 per unit. We received proceeds of $434 million, net of offering costs. During the nine months ended September 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 offering costs of $2 million, which were used to finance growth opportunities and for general corporate purposes. In June 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 September 30, 2013, we have issued no securities under this registration statement. 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. As of September 30, 2013, the unused capacity under the Credit Agreement was $788 million, all of which was available for general working capital purposes, providing liquidity to continue to execute on our growth plans.

We raised our distribution for the quarter, resulting in a 6% increase in our quarterly distribution rate over the rate declared for the third quarter of 2012. The distribution reflects 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 $20 million and $30 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 Front Range pipeline, 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, the Eagle plant and the O'Connor plant expansion, 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.

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, including commodity derivative activity, 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 cash expenditures made to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets. 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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Reconciliation of Non-GAAP Measures	Three Months Ended September 30, 2013 (Millions)	2012	Nine Months Ended September 30, 2013	2012
Reconciliation of net income attributable to partners to gross margin:				
Net (loss) income attributable to partners	$(1)	$8	$153	$127
Interest expense	14	8	40	32
Income tax expense	1	—	2	1
Operating and maintenance expense	56	53	152	145
Depreciation and amortization expense	25	19	68	68
General and administrative expense	15	20	47	56
Other (income) expense	(1)	—	3	—
Earnings from unconsolidated affiliates	(7)	(9)	(23)	(17)
Net income attributable to noncontrolling interests	3	2	10	8
Gross margin	$105	$101	$452	$420
Non-cash commodity derivative mark-to-market (a)	$(50)	$(23)	$(2)	$19
Reconciliation of segment net income attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net income attributable to partners	$11	$25	$161	$171
Operating and maintenance expense	47	44	128	121
Depreciation and amortization expense	22	16	61	61
Loss (earnings) from unconsolidated affiliates	1	(4)	—	(12)
Net income attributable to noncontrolling interests	3	2	10	8
Segment gross margin	$84	$83	$360	$349
Non-cash commodity derivative mark-to-market (a)	$(49)	$(21)	$—	$5
NGL Logistics segment:				
Segment net income attributable to partners	$19	$14	$61	$34
Operating and maintenance expense	5	5	13	13
Depreciation and amortization expense	2	2	5	5
Other income	(1)	—	(1)	—
Earnings from unconsolidated affiliates	(8)	(5)	(23)	(5)
Segment gross margin	$17	$16	$55	$47
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners	$(1)	$(3)	$20	$11
Operating and maintenance expense	4	4	11	11
Depreciation and amortization expense	1	1	2	2
Other expense	—	—	4	—
Segment gross margin	$4	$2	$37	$24
Non-cash commodity derivative mark-to-market (a)	$(1)	$(2)	$(2)	$14

(a)

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

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	Three Months Ended September 30,		Nine Months Ended September 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)	$11	$25	$161	$171
Non-cash commodity derivative mark-to-market	49	21	—	(5)
Depreciation and amortization expense	22	16	61	61
Noncontrolling interest on depreciation and income tax	(1)	(1)	(4)	(5)
Adjusted Segment EBITDA	$81	$61	$218	$222
NGL Logistics segment:				
Segment net income attributable to partners	$19	$14	$61	$34
Depreciation and amortization expense	2	2	5	5
Adjusted Segment EBITDA	$21	$16	$66	$39
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners (b)	$(1)	$(3)	$20	$11
Non-cash commodity derivative mark-to-market	1	2	2	(14)
Depreciation and amortization expense	1	1	2	2
Adjusted Segment EBITDA	$1	$—	$24	$(1)

(a) Includes less than $1 million and $2 million of lower of cost or market adjustments for the three and nine months ended September 30, 2013, respectively, and no lower of cost or market adjustments for the three months ended September 30, 2012. We recognized $4 million of lower of cost or market adjustments for the nine months ended September 30, 2012.

(b) Includes $1 million and less than $1 million of lower of cost or market adjustments for the three months ended September 30, 2013 and 2012, respectively. We recognized $2 million and $15 million of lower of cost or market adjustments for the nine months ended September 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 nine months ended September 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 nine months ended September 30, 2013 and 2012. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2013 vs. 2012		Variance Nine 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	$608	$551	$1,868	$1,748	$57	10 %	$120	7 %
NGL Logistics	17	16	55	47	1	6 %	8	17 %
Wholesale Propane Logistics	47	37	255	314	10	27 %	(59)	(19)%
Total operating revenues	672	604	2,178	2,109	68	11 %	69	3 %
Gross margin (d):								
Natural Gas Services	84	83	360	349	1	1 %	11	3 %
NGL Logistics	17	16	55	47	1	6 %	8	17 %
Wholesale Propane Logistics	4	2	37	24	2	100 %	13	54 %
Total gross margin	105	101	452	420	4	4 %	32	8 %
Operating and maintenance expense	(56)	(53)	(152)	(145)	3	6 %	7	5 %
Depreciation and amortization expense	(25)	(19)	(68)	(68)	6	32 %	—	—
General and administrative expense	(15)	(20)	(47)	(56)	(5)	(25)%	(9)	(16)%
Other income (expense)	1	—	(3)	—	1	100 %	3	100 %
Earnings from unconsolidated affiliates (e)	7	9	23	17	(2)	(22)%	6	35 %
Interest expense	(14)	(8)	(40)	(32)	6	75 %	8	25 %
Income tax expense	(1)	—	(2)	(1)	1	100 %	1	100 %
Net income attributable to noncontrolling interests	(3)	(2)	(10)	(8)	1	50 %	2	25 %
Net (loss) income attributable to partners	$(1)	$8	$153	$127	$(9)	(113)%	$26	20 %
Other data:								
Non-cash commodity derivative mark-to-market	$(50)	$(23)	$(2)	$19	$27	117 %	$(21)	(111)%
Natural gas throughput (MMcf/d) (e)	2,247	2,307	2,273	2,268	(60)	(3)%	5	—
NGL gross production (Bbls/d) (e)	117,881	105,252	114,924	105,556	12,629	12 %	9,368	9 %
NGL pipelines throughput (Bbls/d) (e)	92,524	69,863	90,041	75,115	22,661	32 %	14,926	20 %
Propane sales volume (Bbls/d)	10,156	9,128	18,734	18,383	1,028	11 %	351	2 %

(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.

(d) 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.

(e) 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 September 30, 2013 vs. Three Months Ended September 30, 2012

Total Operating Revenues — Total operating revenues increased $68 million in 2013 compared to 2012 primarily as a result of the following:

- $45 million increase primarily attributable to increased natural gas prices and prices related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems, partially offset by decreased NGL prices;
- $18 million increase primarily attributable to increased volumes at our Eagle Ford system, partially offset by decreased volumes related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems;
- $9 million increase attributable to higher propane prices and increased volumes in our Wholesale Propane segment. 2012 results reflect a lack of demand due to the industry's excess inventory resulting from near record warm weather; and
- $8 million increase attributable to 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:

- $12 million decrease related to commodity derivative activity as a result of a $13 million decrease in our Natural Gas Services segment, partially offset by a $1 million increase in our Wholesale Propane segment. This net decrease includes a $27 million increase in unrealized commodity derivative losses, partially offset by a $15 million increase in realized cash settlement gains.

Gross Margin — Gross margin remained relatively constant in 2013 compared to 2012.

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

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

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.

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, decreased in 2013 compared to 2012 as a result of a non-cash write off of fixed assets, lower volumes and a third party outage related to Discovery. Additionally, 2012 results for Discovery reflect the settlement of commercial disputes. This decrease was partially offset by increased earnings in 2013 compared to 2012 as a result of the Mont Belvieu Enterprise fractionator de-bottleneck project in 2013. 2012 results for the Mont Belvieu 1 fractionator reflect lower margin and higher operating expenses related to a planned turnaround. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Interest Expense — Interest expense increased in 2013 compared to 2012 as a result of higher outstanding debt balances.

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, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system.

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Nine Months Ended September 30, 2013 vs. Nine Months Ended September 30, 2012

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

- $69 million increase primarily attributable to increased natural gas prices and prices related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems, partially offset by decreased NGL prices;
- $30 million increase attributable to 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; and
- $25 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 related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems, and a plant turnaround at our Eagle Ford system.

These increases were partially offset by:

- $44 million decrease attributable to lower propane prices, partially offset by increased volumes in our Wholesale Propane Logistics segment. 2012 results reflect a lack of demand due to the industry's excess inventory resulting from near record warm weather; and
- $11 million decrease related to commodity derivative activity as a result of a $15 million decrease in our Wholesale Propane segment, partially offset by a $4 million increase in our Natural Gas Services segment. This net decrease includes unrealized commodity derivative losses in 2013 as compared to gains in 2012 for a net impact of $21 million, partially offset by an $10 million increase in realized cash settlement gains.

Gross Margin — Gross margin increased $32 million in 2013 compared to 2012, primarily as a result of the following:

- $13 million increase for our Wholesale Propane Logistics segment, primarily due to increased unit margins and exporting propane from our Chesapeake terminal in 2013, partially offset by a decrease related to commodity derivative activities and suspending the import of supply in 2013. 2012 results reflect a non-cash lower of cost or market inventory adjustment of $15 million recognized in the second quarter, and reduced demand due to the industry's excess inventory resulting from near record warm weather;
- $11 million increase for our Natural Gas Services segment, primarily related to increased commodity derivative activities, higher volumes, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system, higher unit margins associated with our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems, and a decrease in the lower of cost or market adjustment recognized in 2013, partially offset by a decrease resulting from lower commodity prices, which reflect the unhedged portion of the Eagle Ford system associated with DCP Midstream, LLC’s ownership, and lower volumes across certain assets; and
- $8 million increase for our NGL Logistics segment as a result of increased throughput on certain of our pipelines and increased activity at our NGL storage facility.

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

Depreciation and Amortization Expense — Depreciation and amortization remained constant in 2013 compared to 2012 as a result of growth in our business, offset by 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.

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

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 and the Mont Belvieu Enterprise fractionator de-bottleneck project. These increases were partially offset by lower results at Discovery due to a non-cash write off of fixed assets, lower NGL prices, reduced throughput volumes, timing of expenditures and the 2012 settlement of commercial disputes. 2012 results for the Mont Belvieu 1 fractionator reflect lower margin and higher operating expenses related to a planned turnaround. Settlements related to our commodity derivatives on our unconsolidated affiliates are included in segment gross margin.

Interest Expense — Interest expense increased in 2013 compared to 2012 as a result of higher outstanding debt balances.

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, improved NGL recoveries and an annual minimum volume commitment fee 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 80% interest in the Eagle Ford system, our wholly-owned Eagle Plant, our East Texas system, our Southeast Texas system, our Michigan system, our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our 75% interest in the Colorado system, our 40% interest in Discovery, and our O'Connor plant (under construction as of September 30, 2013):

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2013 vs. 2012		Variance Nine 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	$594	$531	$1,698	$1,604	$63	12 %	$94	6 %
Transportation, processing and other	46	39	132	110	7	18 %	22	20 %
(Losses) gains from commodity derivative activity	(32)	(19)	38	34	13	68 %	4	12 %
Total operating revenues	608	551	1,868	1,748	57	10 %	120	7 %
Purchases of natural gas and NGLs	(524)	(468)	(1,508)	(1,399)	56	12 %	109	8 %
Segment gross margin (c)	84	83	360	349	1	1 %	11	3 %
Operating and maintenance expense	(47)	(44)	(128)	(121)	3	7 %	7	6 %
Depreciation and amortization expense	(22)	(16)	(61)	(61)	6	38 %	—	—
(Loss) earnings from unconsolidated affiliates (d)	(1)	4	—	12	(5)	(125)%	(12)	(100)%
Segment net income	14	27	171	179	(13)	(48)%	(8)	(4)%
Segment net income attributable to noncontrolling interests	(3)	(2)	(10)	(8)	1	50 %	2	25 %
Segment net income attributable to partners	$11	$25	$161	$171	$(14)	(56)%	$(10)	(6)%
Other data:								
Non-cash commodity derivative mark-to-market	$(49)	$(21)	$—	$5	$28	133 %	$(5)	(100)%
Natural gas throughput (MMcf/d) (d)	2,247	2,307	2,273	2,268	(60)	(3)%	5	—
NGL gross production (Bbls/d) (d)	117,881	105,252	114,924	105,556	12,629	12 %	9,368	9 %

(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 our investment and the underlying equity of the entity.

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

Total Operating Revenues — Total operating revenues increased $57 million in 2013 compared to 2012, primarily as a result of the following:

- $53 million increase primarily attributable to increased volumes at our Eagle Ford system and the operation of our fee-based, wholly-owned Eagle plant;
- $34 million increase attributable to increased natural gas prices; and
- $14 million increase attributable to increased prices related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems.

These increases were partially offset by:

- $28 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems;
- $13 million decrease related to commodity derivative activity. This includes an increase in unrealized commodity derivative losses in 2013 compared to 2012 of $28 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 $15 million; and
- $3 million decrease primarily attributable to decreased NGL prices.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $56 million in 2013 compared to 2012 primarily as a result of increased volumes across certain assets and higher natural gas prices.

Segment Gross Margin — Segment gross margin increased $1 million in 2013 compared to 2012, primarily as a result of the following:

- $21 million increase as a result of higher volumes, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system, partially offset by lower volumes across certain assets.

This increase was partially offset by:

- $13 million decrease related to commodity derivative activities as discussed above; and
- $7 million decrease attributable to lower volumes related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems.

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

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 as a result of a non-cash write off of fixed assets, lower volumes and a third party outage. 2012 results reflect the settlement of commercial disputes. 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, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system.

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

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 and improved NGL recoveries, partially offset by lower volumes across certain assets. 2012 results reflect lower volumes as certain of our assets were required to curtail NGL production due to a downstream outage.

Nine Months Ended September 30, 2013 vs. Nine Months Ended September 30, 2012

Total Operating Revenues — Total operating revenues increased $120 million in 2013 compared to 2012, primarily as a result of the following:

- $157 million increase attributable to increased natural gas prices;
- $74 million increase attributable to increased prices related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems;
- $65 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;
- $22 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; and
- $4 million increase related to commodity derivative activity. This includes an increase in realized cash settlement gains in 2013 compared to 2012 of $9 million, partially offset by a decrease in unrealized commodity derivative gains in 2013 compared to 2012 of $5 million due to movements in forward prices of commodities.

These increases were partially offset by:

- $162 million decrease attributable to decreased NGL prices; and
- $40 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems.

Purchases of Natural Gas and NGLs - Purchases of natural gas and NGLs increased $109 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 $11 million in 2013 compared to 2012, primarily as a result of the following:

- $34 million increase as a result of higher volumes, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system, partially offset by lower volumes across certain assets;
- $4 million increase related to commodity derivative activity as discussed above; and
- $2 million increase attributable to higher unit margins associated with our natural gas storage and pipeline assets in our Southeast Texas and Northern Louisiana systems and a decrease in the lower of cost or market adjustment recognized in 2013 as compared to 2012.

These increases were partially offset by:

- $29 million decrease as a result of lower commodity prices, which reflect the unhedged portion of the Eagle Ford system associated with DCP Midstream, LLC’s ownership during the nine months ended September 30, 2013.

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

Depreciation and Amortization Expense — Depreciation and amortization expense remained constant in 2013 compared to 2012 as a result of growth in our business, offset by 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.

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 a non-cash write off of fixed assets, lower results due to lower NGL prices, reduced throughput volumes and timing of expenditures. 2012 results reflect the settlement of commercial disputes. 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 increased in 2013 compared to 2012, primarily as a result of higher volumes, improved NGL recoveries and an annual minimum volume commitment fee at our Eagle Ford system, partially offset by a plant turnaround at our Eagle Ford system.

Natural Gas Throughput - Natural gas throughput remained constant in 2013 compared to 2012 as a result of higher volumes due to the operation of our wholly-owned Eagle plant, offset by 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 lower volumes across certain assets. 2012 results reflect lower volumes as certain of our assets were required to curtail NGL production due to a downstream outage.

Results of Operations — NGL Logistics Segment

This segment includes the NGL storage facility in Michigan, our 20% interest in the Mont Belvieu 1 fractionator, our 12.5% interest in the Mont Belvieu Enterprise fractionator, the Black Lake and Wattenberg interstate NGL pipelines, the DJ Basin NGL fractionators in Colorado, the Seabreeze and Wilbreeze intrastate NGL pipeline, our 33.33% interest in the Front Range interstate NGL pipeline (currently under construction), and our 10% interest in the Texas Express intrastate NGL pipeline (under construction as of September 30, 2013):

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	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2013 vs. 2012		Variance Nine 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	17	16	55	47	1	6 %	8	17 %
Total operating revenues	17	16	55	47	1	6 %	8	17 %
Purchases of NGLs	—	—	—	—	—	—	—	—
Segment gross margin (a)	17	16	55	47	1	6 %	8	17 %
Operating and maintenance expense	(5)	(5)	(13)	(13)	—	—	—	—
Depreciation and amortization expense	(2)	(2)	(5)	(5)	—	—	—	—
Other income	1	—	1	—	1	100 %	1	100 %
Earnings from unconsolidated affiliates (b)	8	5	23	5	3	60 %	18	360 %
Segment net income attributable to partners	$19	$14	$61	$34	$5	36 %	$27	79 %
Other data:								
NGL pipelines throughput (Bbls/d) (b)	92,524	69,863	90,041	75,115	22,661	32 %	14,926	20 %

(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. Earnings for Mont Belvieu 1 include the amortization of the net difference between the carrying amount of our investment and the underlying equity of the entity.

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

Total Operating Revenues — Total operating revenues increased in 2013 compared to 2012 as result of increased throughput on certain of our pipelines.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 as result of 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 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 Mont Belvieu Enterprise fractionator de-bottleneck project. 2012 results for the Mont Belvieu 1 fractionator reflect lower margin and higher operating expenses related to a planned turnaround.

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

Nine Months Ended September 30, 2013 vs. Nine Months Ended September 30, 2012
Total Operating Revenues — Total operating revenues increased in 2013 compared to 2012 as result of increased throughput on certain of our pipelines and increased activity at our NGL storage facility.

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Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 as result of increased throughput on certain of our pipelines and increased activity at our NGL storage facility.
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 and the Mont Belvieu Enterprise fractionator de-bottleneck project. 2012 results for the Mont Belvieu 1 fractionator reflect lower margin and higher operating expenses related to a planned turnaround.
NGL Pipelines Throughput — NGL pipelines throughput increased in 2013 compared to 2012 as a result of volume growth on our pipelines.

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 September 30,		Nine Months Ended September 30,		Variance Three Months 2013 vs. 2012		Variance Nine Months 2013 vs. 2012	
	2013	2012	2013	2012	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$47	$38	$254	$298	$9	24 %	$(44)	(15)%
Other	—	—	—	—	—	—	—	—
(Losses) gains from commodity derivative activity	—	(1)	1	16	1	100 %	(15)	(94)%
Total operating revenues	47	37	255	314	10	27 %	(59)	(19)%
Purchases of propane	(43)	(35)	(218)	(290)	8	23 %	(72)	(25)%
Segment gross margin (a)	4	2	37	24	2	100 %	13	54 %
Operating and maintenance expense	(4)	(4)	(11)	(11)	—	—	—	—
Depreciation and amortization expense	(1)	(1)	(2)	(2)	—	—	—	—
Other expense	—	—	(4)	—	—	—	4	100 %
Segment net (loss) income attributable to partners	$(1)	$(3)	$20	$11	$2	67 %	$9	82 %
Other data:								
Non-cash commodity derivative mark-to-market	$(1)	$(2)	$(2)	$14	$(1)	(50)%	$(16)	(114)%
Propane sales volume (Bbls/d)	10,156	9,128	18,734	18,383	1,028	11 %	351	2 %

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

Total Operating Revenues — Total operating revenues increased by $10 million in 2013 compared to 2012, primarily as a result of the following:

- $5 million increase attributable to higher propane prices;

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- $4 million increase attributable to increased sales volumes. 2012 results reflect a lack of demand due to the industry's excess inventory resulting from near record warm weather; and
- $1 million increase related to commodity derivative activity, which represents a decrease in unrealized losses in 2013 compared to 2012.

Purchases of Propane — Purchases of propane increased in 2013 compared to 2012 as a result of higher propane prices, which impacts both sales and purchases, and increased sales volume. 2012 results reflect a lack of demand due to the industry’s excess inventory resulting from near record warm weather. 2012 also reflects a modest recovery of the lower of cost or market inventory adjustment recognized in the second quarter through the sale of inventory in the third quarter.

Segment Gross Margin — Segment gross margin increased in 2013 compared to 2012 primarily due to a $1 million increase related to commodity derivative activities as discussed above and increased unit margins. 2012 results reflect a lack of demand due to the industry’s excess inventory resulting from near record warm weather. 2012 also reflects a modest recovery of the lower of cost or market inventory adjustment recognized in the second quarter through the sale of inventory in the third quarter.

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.

Propane Sales Volume — Propane sales volumes increased in 2013 compared to 2012. 2012 results reflect a lack of demand due to the industry’s excess inventory resulting from near record warm weather.

Nine Months Ended September 30, 2013 vs. Nine Months Ended September 30, 2012

Total Operating Revenues — Total operating revenues decreased by $59 million in 2013 compared to 2012, primarily as a result of the following:

- $48 million decrease attributable to lower propane prices; and
- $15 million decrease related to commodity derivative activity. This includes unrealized commodity derivative losses in 2013 compared to gains in 2012 due to movements in forward prices of commodities for a net impact of $16 million, partially offset by an increase in realized cash settlement gains in 2013 compared to 2012 of $1 million.

These decreases were partially offset by:

- $4 million increase attributable to increased volumes. 2012 results reflect a lack of demand due to the industry’s excess inventory resulting from 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, suspending the import of supply in 2013 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 in 2013 and reduced demand in 2012 due to the industry’s excess inventory resulting from near record warm weather.

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 in 2013, partially offset by a $15 million decrease related to commodity derivative activities as discussed above and suspending the import of supply in 2013. 2012 results reflect a non-cash lower of cost or market inventory adjustment of $15 million and reduced demand due to the industry’s excess inventory resulting from near record warm weather.

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.

Other Expense — Other expense represents a write off of approximately $4 million in construction work in progress in 2013 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;
- issuance of commercial paper;
- 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 transactions with 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.

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 may be 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 November 1, 2013, we had approximately $720 million of unused capacity under the Credit Agreement.

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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 2013, we issued 9,000,000 common units at $50.04 per unit. We received proceeds of $434 million, net of offering costs.

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 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.

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 September 30, 2013, we have issued no securities under this registration statement.

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 nine months ended September 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 offering costs of $2 million, which were used to finance growth opportunities and general corporate purposes. As of September 30, 2013, no common units remained available for sale pursuant to this equity distribution agreement.

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. 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.

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 $62 million as of September 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 $63

million and $18 million as of September 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 September 30, 2013, we had $1 million in cash and cash equivalents. Other than the cash held by consolidated subsidiaries we do not wholly own of less than $1 million, this cash balance was available for general partnership purposes.

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

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	Nine Months Ended September 30,	
	2013	2012
	(Millions)	
Net cash provided by operating activities	$264	$152
Net cash used in investing activities	$(1,209)	$(855)
Net cash provided by financing activities	$944	$704

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 $41 million for our net hedge cash settlements for the nine months ended September 30, 2013, of which less than $1 million was associated with rebalancing our portfolio, and $31 million for our net hedge cash settlements for the nine months ended September 30, 2012.

We received cash distributions from unconsolidated affiliates of $32 million and $16 million during the nine months ended September 30, 2013 and 2012, respectively. Distributions exceeded earnings by $9 million for the nine months ended September 30, 2013, and earnings exceeded distributions by $1 million for the nine months ended September 30, 2012.

Net Cash Used in Investing Activities — Net cash used in investing activities during the nine months ended September 30, 2013 was comprised of: (1) acquisition expenditures of $782 million related to our acquisition of the additional 46.67% interest in the Eagle Ford system for $486 million, the O'Connor plant for $210 million and Front Range for $86 million; (2) capital expenditures of $277 million (our portion of which was $244 million and the noncontrolling interests portion was $33 million); and (3) investments in unconsolidated affiliates of $150 million.

Net cash used in investing activities during the nine months ended September 30, 2012 was comprised of: (1) acquisition expenditures of $405 million, of which $192 million is related to our acquisition of the remaining 66.67% interest in Southeast Texas, $120 million related to our acquisition of the remaining 49.9% interest in East Texas, $63 million related to our acquisition of Crossroads, and $30 million related to our acquisition of the Mont Belvieu fractionators; (2) capital expenditures of $366 million (our portion of which was $312 million and the noncontrolling interests and reimbursable projects portion was $54 million); and (3) investments in unconsolidated affiliates of $86 million; partially offset by (4) a return of investment from unconsolidated affiliate of $1 million; and (5) proceeds from sales of assets of $1 million.

Net Cash Provided by Financing Activities — Net cash provided by financing activities during the nine months ended September 30, 2013 was comprised of: (1) proceeds from debt of $1,826 million, offset by payments of $1,646 million, for net borrowing of debt of $180 million; (2) proceeds from the issuance of common units net of offering costs of $995 million; (3) contributions from noncontrolling interests of $40 million; (4) change in advances to predecessor from DCP Midstream, LLC of $32 million; and (5) contributions from DCP Midstream, LLC of $1 million; partially offset by (6) distributions to our limited partners and general partner of $195 million; (7) excess purchase price over acquired interests and commodity hedges of $86 million; (8) distributions to noncontrolling interests of $16 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 nine months ended September 30, 2012 was comprised of: (1) proceeds from debt of $1,353 million, offset by payments of $1,062 million, for net borrowing of debt of $291 million; (2) proceeds from the issuance of common units net of offering costs of $445 million; (3) net change in advances to predecessor from DCP Midstream, LLC of $164 million and from noncontrolling interest of $44 million;

and (4) contributions from DCP Midstream, LLC of $7 million; partially offset by (5) distributions to our limited partners and general partner of $128 million; (6) excess purchase price over acquired interests of $110 million (7) distributions to noncontrolling interests of $5 million; and (8) payment of deferred financing costs of $4 million.

During the nine months ended September 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

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Agreement, was not less than $151 million and did not exceed $607 million. The weighted-average indebtedness outstanding for the nine months ended September 30, 2013 was $298 million.

As of September 30, 2013, we had unused capacity under the revolving credit facility of $788 million, all of which was available for general working capital purposes.

During the nine months ended September 30, 2013, we had the following net movements on our revolving credit facility:

- $434 million repayment financed by the issuance of 9,000,000 common units in August 2013; and
- $441 million repayment financed by the issuance of 12,650,000 common units in March 2013; partially offset by
- $209 million borrowings to fund the acquisition of the O'Connor plant;
- $186 million net borrowing activity;
- $86 million borrowings to fund the acquisition of the Front Range pipeline; and
- $80 million borrowings primarily to reimburse DCP Midstream, LLC for its proportionate share of the capital spent to date, at closing, by the Eagle Ford system for the construction of the Goliad plant and for preformation capital expenditures.

During the nine months ended September 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
- $37 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 11 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 to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets; and
- expansion capital expenditures, which are cash expenditures to increase our cash flows, operating or earnings capacity. Expansion capital expenditures include acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines and well connects, 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).

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $20 million and $30 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 Front Range pipeline, 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, the Eagle plant and the O'Connor plant expansion, 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.

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

	Nine months ended September 30, 2013			Nine months ended September 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	$16	$228	$244	$15	$297	$312
Noncontrolling interest portion and reimbursable projects (a)	1	32	33	5	49	54
Total	$17	$260	$277	$20	$346	$366

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

In addition, we invested cash in unconsolidated affiliates of $150 million and $85 million, net of returns, during the nine months ended September 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 $195 million during the nine months ended September 30, 2013, as compared to $128 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 September 30, 2013, the outstanding balance on the revolving credit facility was $211 million resulting in unused revolver capacity of $788 million, all of which 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 September 30, 2013 and December 31, 2012, we had $1 million outstanding letters of credit issued under the Credit Agreement. Amounts undrawn under the revolving credit facility are available to repay amounts borrowed under our commercial paper program, if necessary.

As of September 30, 2013, the weighted-average interest rate on our revolving credit facility was 1.44% 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 September 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)	$2,232	$62	$361	$803	$1,006
Operating lease obligations (b)	96	17	26	18	35
Purchase obligations (c)	306	231	54	21	—
Other long-term liabilities (d)	27	—	3	—	24
Total	$2,661	$310	$444	$842	$1,065

(a) Includes interest payments on long-term debt that has been hedged and on debt securities that have been issued. These interest payments are $62 million, $111 million, $92 million, and $156 million for less than one year, one to three years, three to five years, and thereafter, respectively.

(b) Our operating lease obligations are contractual obligations, and primarily consist of our leased marine propane terminal and railcar leases, both of which provide supply and storage infrastructure for our Wholesale Propane Logistics business. Operating lease obligations also include natural gas storage for the Pelico system in our Northern Louisiana 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 September 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, $1 million of environmental reserves and $2 million of firm transportation commitments recognized in the September 30, 2013 condensed consolidated balance

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sheet. In addition, $6 million of deferred state income taxes was excluded as cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year.
We have no items that are classified as off balance sheet obligations.

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 November 1, 2013:
Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
October 2013 — December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$5.06/MMBtu
October 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
October 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 — December 2015	Natural Gas	(8,677) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(4,041) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
October 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
April 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
October 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	(1,642) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$85.15-$101.30/Bbl
April 2016 — December 2016	Crude Oil	(1,500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$85.15-$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
October 2013 — December 2014	Natural Gas	500 MMBtu/d	IFERC Monthly Index Price for Texas Gas Transmission (b)	$4.93/MMBtu
October 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).

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(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).

Commodity Collar Arrangements

Period	Commodity	Notional Volume	Reference Price	Collar Price Range
October 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.
(b) 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 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	$5

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 September 30, 2013:
Inventory

Period	Commodity	Notional Volume - Long Positions	Fair Value	Weighted Average Price
			(millions)	
September 30, 2013	Natural Gas	7,044,776 MMBtu	$25	$3.57/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume -(Short)/Long Positions	Fair Value	Price Range
			(millions)	
October 2013-October 2014	Natural Gas	(46,650,000) MMBtu	$6	$3.42-$4.16/MMBtu
October 2013-October 2014	Natural Gas	39,285,000 MMBtu	$(5)	$3.30-$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 September 30, 2013, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of September 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 September 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 13 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 and subsequent filings on Form 10-Q. 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 and subsequent filings on Form 10-Q. 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.

Item 5. Other Information

On November 6, 2013, DCP Midstream, LLC, the sole member of DCP Midstream GP, LLC, or the General Partner, the general partner of our general partner, entered into Amendment No. 3 to the General Partner's Amended and Restated Limited Liability Agreement, or the Amendment, in order to amend and restate in its entirety Section 6.01(a) thereof. The Amendment clarifies the authority of our Board of Directors to delegate any of its responsibilities to our management notwithstanding any powers that may be exclusive to a board of directors under the Delaware General Corporation Law.

The foregoing description of the Amendment is not complete and is qualified in its entirety by reference to the full and complete terms of the Amendment, which is attached to this Quarterly Report on Form 10-Q as Exhibit 3.3 and is incorporated in this Item 5 by reference.

Item 6. Exhibits

Exhibit Number		Description
2.1	*	Purchase and Sale Agreement (O'Connor 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		Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated November 6, 2013.
3.4	*	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).
3.5	*	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).
3.6	*	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).
3.7	*	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).
10.2	*	Form of Commercial Paper Dealer Agreement among DCP Midstream Operating, LP, DCP Midstream Partners, LP, and the Dealer party thereto (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 October 29, 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 and nine months ended September 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 November 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
	Title:	Senior Vice President and Chief Financial Officer (Principal Financial Officer)

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