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 (Address of principal executive offices)	80202 (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

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.

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

1. Description of Business and Basis of Presentation

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

We are a Delaware limited partnership that was formed in August 2005. Our partnership includes: our natural gas services segment (which includes our 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)	Consolidate Eagle Ford system (a)	Condensed Consolidated DCP Midstream Partners, LP (As currently reported)
	(Millions)		
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:

		Carrying Value as of	
	Percentage Ownership	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

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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

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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	$—	$—	$ —