Table of Contents

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

or

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

For the transition period from to

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

As of July 31, 2014, there were outstanding 110,456,567 common units representing limited partner interests.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2014

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Bbl	barrel
Bbls/d	barrels per day
Bcf	billion cubic feet
Bcf/d	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	thousand barrels
MBbls/d	thousand barrels per day
MMBtu	million Btus
MMBtu/d	million Btus per day
MMcf	million cubic feet
MMcf/d	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,” “estimate,” “potential,” “plan,” “forecast” and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in “Item 1A. Risk Factors” in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2013, 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;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- 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 and NGL infrastructure in light of competition;
- our ability to execute our asset integrity and safety programs to continue the safe and reliable operation of our assets;
- 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 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 and start up 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, weather-related conditions 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;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- the amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs;
- industry changes, including the impact of consolidations, alternative energy sources, technological advances and changes in competition; and
- the amount of collateral we may be required to post from time to time in our transactions.

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

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

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

	June 30, 2014	December 31, 2013
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57	$ 12
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1 million	94	130
Affiliates	223	212
Inventories	32	67
Unrealized gains on derivative instruments	78	79
Other	2	3
Total current assets	486	503
Property, plant and equipment, net	3,207	3,046
Goodwill	154	154
Intangible assets, net	124	129
Investments in unconsolidated affiliates	1,426	627
Unrealized gains on derivative instruments	42	87
Other long-term assets	29	21
Total assets	$ 5,468	$ 4,567
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 226	$ 232
Affiliates	30	43
Short-term borrowings	—	335
Unrealized losses on derivative instruments	17	28
Accrued interest	22	13
Capital spending accrual	30	24
Other	54	48
Total current liabilities	379	723
Long-term debt	2,310	1,590
Unrealized losses on derivative instruments	6	1
Other long-term liabilities	42	40
Total liabilities	2,737	2,354
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	40
Limited partners (109,929,567 and 89,045,139 common units issued and outstanding, respectively)	2,694	1,948
General partner	14	8
Accumulated other comprehensive loss	(9)	(11)
Total partners' equity	2,699	1,985
Noncontrolling interests	32	228
Total equity	2,731	2,213
Total liabilities and equity	$ 5,468	$ 4,567

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 206	$ 225	$ 577	$ 508
Sales of natural gas, propane, NGLs and condensate to affiliates	548	435	1,190	837
Transportation, processing and other	55	50	106	96
Transportation, processing and other to affiliates	25	11	57	29
(Losses) gains from commodity derivative activity, net	(11)	4	(14)	2
(Losses) gains from commodity derivative activity, net — affiliates	(11)	67	(23)	69
Total operating revenues	812	792	1,893	1,541
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	622	534	1,407	1,058
Purchases of natural gas, propane and NGLs from affiliates	54	50	154	123
Operating and maintenance expense	56	52	101	98
Depreciation and amortization expense	28	23	54	44
General and administrative expense	3	5	8	10
General and administrative expense — affiliates	12	11	23	22
Other expense	—	—	1	4
Total operating costs and expenses	775	675	1,748	1,359
Operating income	37	117	145	182
Interest expense	(23)	(14)	(42)	(26)
Earnings from unconsolidated affiliates	16	8	19	16
Income before income taxes	30	111	122	172
Income tax expense	(1)	—	(4)	(1)
Net income	29	111	118	171
Net income attributable to noncontrolling interests	—	(4)	(10)	(7)
Net income attributable to partners	29	107	108	164
Net income attributable to predecessor operations	—	(5)	(6)	(16)
General partner's interest in net income	(27)	(16)	(53)	(31)
Net income allocable to limited partners	$ 2	$ 86	$ 49	$ 117
Net income per limited partner unit — basic and diluted	0.02	$ 1.11	$ 0.49	$ 1.64
Weighted-average limited partner units outstanding — basic and diluted	108.4	77.3	100.9	71.3

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Net income	$ 29	$ 111	$ 118	$ 171
Other comprehensive income:				
Reclassification of cash flow hedge losses into earnings	—	1	2	2
Total other comprehensive income	—	1	2	2
Total comprehensive income	29	112	120	173
Total comprehensive income attributable to noncontrolling interests	—	(4)	(10)	(7)
Total comprehensive income attributable to partners	$ 29	$ 108	$ 110	$ 166

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2014	2013
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 118	$ 171
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	54	44
Earnings from unconsolidated affiliates	(19)	(16)
Distributions from unconsolidated affiliates	40	22
Net unrealized losses (gains) on derivative instruments	43	(48)
Deferred income taxes, net	2	—
Other, net	5	6
Change in operating assets and liabilities, which (used) provided cash, net of effects of acquisitions:		
Accounts receivable	26	(26)
Inventories	35	39
Accounts payable	(19)	72
Accrued interest	9	6
Other current assets and liabilities	7	12
Other long-term assets and liabilities	(1)	(1)
Net cash provided by operating activities	300	281
INVESTING ACTIVITIES:		
Capital expenditures	(151)	(195)
Acquisitions, net of cash acquired	(102)	(486)
Acquisition of unconsolidated affiliates	(669)	—
Investments in unconsolidated affiliates	(93)	(87)
Proceeds from sales of assets	17	—
Net cash used in investing activities	(998)	(768)
FINANCING ACTIVITIES:		
Proceeds from long-term debt	719	1,079
Payments of long-term debt	—	(960)
Payments of commercial paper, net	(335)	—
Payments of deferred financing costs	(9)	(4)
Excess purchase price over acquired interests and commodity hedges	(15)	(101)
Proceeds from issuance of common units, net of offering costs	787	563
Net change in advances to predecessor from DCP Midstream, LLC	(6)	21
Distributions to limited partners and general partner	(192)	(123)
Distributions to noncontrolling interests	(11)	(10)
Purchase of additional interest in a subsidiary	(198)	—
Contributions from noncontrolling interests	3	31
Distributions to DCP Midstream, LLC	—	(3)
Contributions from DCP Midstream, LLC	—	1
Net cash provided by financing activities	743	494
Net change in cash and cash equivalents	45	7
Cash and cash equivalents, beginning of period	12	2
Cash and cash equivalents, end of period	$ 57	$ 9

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENT 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, 2014	$ 40	$ 1,948	$ 8	$ (11)	$ 228	$ 2,213
Net income	6	49	53	—	10	118
Other comprehensive income	—	—	—	2	—	2
Net change in parent advances	(6)	—	—	—	—	(6)
Acquisition of Lucerne 1 plant	(40)	—	—	—	—	(40)
Issuance of 4,497,158 units to DCP Midstream, LLC and affiliates	—	225	—	—	—	225
Excess purchase price over carrying value of interests acquired in March 2014 Transactions	—	(170)	—	—	—	(170)
Issuance of 16,386,000 common units to the public	—	787	—	—	—	787
Distributions to limited partners and general partner	—	(145)	(47)	—	—	(192)
Distributions to noncontrolling interests	—	—	—	—	(11)	(11)
Contributions from noncontrolling interests	—	—	—	—	3	3
Purchase of additional interest in a subsidiary	—	—	—	—	(198)	(198)
Balance, June 30, 2014	$ —	$ 2,694	$ 14	$ (9)	$ 32	$ 2,731

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENT 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	$ 399	$ 1,063	$ —	$ (15)	$ 189	$ 1,636
Net income	16	117	31	—	7	171
Other comprehensive income	—	—	—	2	—	2
Net change in parent advances	21	—	—	—	—	21
Acquisition of additional 46.67% interest in the Eagle Ford system	(395)	—	—	—	—	(395)
Issuance of units for the Eagle Ford system	—	125	—	—	—	125
Issuance of units for 33.33% interest in the Eagle Ford system and NGL hedge	—	(7)	—	—	—	(7)
Excess purchase price over carrying value of acquired investment of 46.67% interest in the Eagle Ford system and commodity hedge	—	(219)	—	—	—	(219)
Issuance of 14,058,547 common units	—	561	—	—	—	561
Distributions to limited partners and general partner	—	(96)	(27)	—	—	(123)
Distributions to noncontrolling interests	—	—	—	—	(10)	(10)
Contributions from noncontrolling interests	—	—	—	—	31	31
Contributions from DCP Midstream, LLC	—	1	—	—	—	1
Distributions to DCP Midstream, LLC	—	(3)	—	—	—	(3)
Balance, June 30, 2013	$ 41	$ 1,542	$ 4	$ (13)	$ 217	$ 1,791

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2014 and 2013
(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 recovering and selling 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 Eagle Ford system; 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 our Piceance system; our 40% interest in Discovery Producer Services LLC, or Discovery, and our DJ Basin system consisting of our O'Connor and Lucerne 1 plants, as well as the Lucerne 2 plant currently under construction), 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 DJ Basin NGL fractionators, the Black Lake and Wattenberg interstate NGL pipelines, the Seabreeze and Wilbreeze intrastate NGL pipelines, our 33.33% interests in each of the Sand Hills, Southern Hills and Front Range interstate NGL pipelines, and our 10% interest in the Texas Express intrastate NGL pipeline), and our wholesale propane logistics segment (which includes six rail terminals, one marine terminal and one pipeline terminal).

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 100% 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 and its affiliates, or Spectra Energy. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC's employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 22% 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.

Our predecessor results consist of the Lucerne 1 plant, which we acquired from DCP Midstream, LLC in March 2014, and a 46.67% interest in the Eagle Ford system, which we acquired from DCP Midstream, LLC in March 2013. 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, but prior to the acquisition of the remaining 20% interest in March 2014, we owned 80% of the Eagle Ford system which we accounted 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 an 80% interest in the Eagle Ford system and our Lucerne 1 plant 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.

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 included 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 six months ended June 30, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014. 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 2013 audited consolidated financial statements and notes thereto included as Exhibit 99.3 in our current report on Form 8-K filed with the SEC on June 13, 2014.

2. New Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2014-09 "Revenue from Contracts with Customers (Topic 606),"* or ASU 2014-09** - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification, or ASC, Topic 605 "Revenue Recognition." This ASU is effective for annual reporting periods beginning after December 15, 2016 and we are currently assessing the impact of adoption on our consolidated results of operations, cash flows and financial position.

3. Acquisitions

On March 31, 2014, DCP Midstream, LLC and its affiliates contributed to us (i) a 33.33% membership interest in DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; (ii) a 33.33% membership interest in DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline; and (iii) the remaining 20% interest in DCP SC Texas GP, or the Eagle Ford system. The Sand Hills pipeline is engaged in the business of transporting NGLs and consists of approximately 720 miles of pipeline, with an expected initial capacity of 200 MBbls/d, and possible further capacity increases with the installation of additional pump stations. The Sand Hills pipeline provides NGL takeaway service from the Permian and Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and at the Mont Belvieu, Texas market hub. The Sand Hills pipeline began taking flows in the fourth quarter of 2012 and was placed into service in June 2013. The Southern Hills pipeline is also engaged in the business of transporting NGLs and consists of approximately 800 miles of pipeline, with an expected capacity of 175 MBbls/d after completion of planned pump stations. The Southern Hills pipeline provides NGL takeaway service from the Midcontinent to fractionation facilities at the Mont Belvieu, Texas market hub. The Southern Hills pipeline began taking flows in the first quarter of 2013 and was placed into service in June 2013.

On March 28, 2014, we acquired from DCP Midstream, LLC and its affiliates (i) a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant; and (ii) a 200 MMcf/d cryogenic natural gas processing plant also located in Weld County, Colorado, or the Lucerne 2 plant, which is currently under construction. The Lucerne 1 plant, along with our O'Connor plant, comprises our DJ Basin system. In conjunction with our acquisition of the Lucerne 1 plant, we entered into a long-term fee-based processing agreement with DCP Midstream, LLC pursuant to which DCP Midstream, LLC 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 DCP Midstream, LLC at the Lucerne 1 plant. The Lucerne 2 plant is expected to be completed in mid-2015 and we have assumed all of the remaining costs to complete this project. In addition, we will enter into a ten-year, fee-based natural gas processing agreement with DCP Midstream, LLC that is effective once the Lucerne 2 plant is placed into service. At that time, the processing agreement with Lucerne 1 will be terminated and the new processing agreement will provide a fixed demand charge on 75% of the capacity of both plants, and a throughput fee on all volumes processed at the Lucerne 1 and 2 plants. Together with the contribution of the Sand Hills and Southern Hills pipelines and the remaining 20% interest in the Eagle Ford system, the acquisition of the Lucerne 1 and 2 plants are collectively referred to hereafter as the March 2014 Transactions.

Total consideration for the March 2014 Transactions at closing was $1,220 million, less customary working capital and other adjustments. $225 million of the consideration was funded by the issuance at closing of 2,098,674 of our common units to DCP Midstream, LLC, 1,399,116 of our common units to DCP LP Holdings, LLC, and 999,368 of our common units to DCP Midstream GP, LP. The remainder of the consideration was financed by a portion of the issuance of 14,375,000 common units to the public and the proceeds from our 5.60% 30-year Senior Notes and 2.70% five-year Senior Notes offering. The total consideration over the carrying value of the net assets of the Sand Hills and Southern Hills pipelines, the remaining 20% of the Eagle Ford system, and the Lucerne 1 and Lucerne 2 plants resulted in an excess purchase price of $170 million which was recorded as a decrease in limited partners' equity in the condensed consolidated statement of changes in equity.

The acquisition of the Lucerne 2 plant and contribution of the Sand Hills pipeline, the Southern Hills pipeline and the remaining 20% interest in the Eagle Ford system represent a transfer of assets between entities under common control. The results for these entities are included prospectively from the date of acquisition or contribution. The acquisition of the Lucerne 1 plant 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 the Lucerne 1 plant for all periods presented, similar to the pooling method. The results of the Sand Hills and Southern Hills pipelines are included in our NGL Logistics segment, and the remaining 20% interest in the Eagle Ford system and the Lucerne 1 and 2 plants are included in our Natural Gas Services segment.

The assets and liabilities of the Lucerne 1 plant are included in the condensed consolidated balance sheets as of June 30, 2014 and December 31, 2013. The following table presents the previously reported December 31, 2013 consolidated balance sheet, condensed and adjusted for the acquisition of the Lucerne 1 plant from DCP Midstream, LLC:

As of December 31, 2013

	DCP Midstream Partners, LP (Condensed, as previously reported on Form 10-K filed on 2/26/14)	Consolidate Lucerne 1 Plant	Consolidated DCP Midstream Partners, LP (As currently reported)
		(Millions)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 12	$ —	$ 12
Accounts receivable	342	—	342
Inventories	67	—	67
Other	82	—	82
Total current assets	503	—	503
Property, plant and equipment, net	3,005	41	3,046
Goodwill and intangible assets, net	283	—	283
Investments in unconsolidated affiliates	627	—	627
Other non-current assets	108	—	108
Total assets	$ 4,526	$ 41	$ 4,567
LIABILITIES AND EQUITY			
Accounts payable and other current liabilities	$ 722	$ 1	$ 723
Long-term debt	1,590	—	1,590
Other long-term liabilities	41	—	41
Total liabilities	2,353	1	2,354
Commitments and contingent liabilities			
Equity:			
Partners' equity			
Net equity	1,956	40	1,996
Accumulated other comprehensive loss	(11)	—	(11)
Total partners' equity	1,945	40	1,985
Noncontrolling interests	228	—	228
Total equity	2,173	40	2,213
Total liabilities and equity	$ 4,526	$ 41	$ 4,567

The results of the Lucerne 1 plant are included in the condensed consolidated statements of operations for the three and six months ended June 30, 2014 and 2013. The following table presents the previously reported consolidated statements of operations for the three and six months ended June 30, 2013, condensed and adjusted for the acquisition of the Lucerne 1 plant from DCP Midstream, LLC:

	DCP Midstream Partners, LP (As previously reported on Form 10-Q filed on 8/6/13)	Consolidate Lucerne 1 Plant	Consolidated DCP Midstream Partners, LP (As currently reported)
Three Months Ended June 30, 2013		(Millions)	
Sales of natural gas, propane, NGLs and condensate	$ 643	$ 17	$ 660
Transportation, processing and other	61	—	61
Gains from commodity derivative activity, net	71	—	71
Total operating revenues	775	17	792
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	573	11	584
Operating and maintenance expense	51	1	52
Depreciation and amortization expense	23	—	23
General and administrative expense	16	—	16
Total operating costs and expenses	663	12	675
Operating income	112	5	117
Interest expense	(14)	—	(14)
Earnings from unconsolidated affiliates	8	—	8
Income before income taxes	106	5	111
Income tax expense	—	—	—
Net income	106	5	111
Net income attributable to noncontrolling interests	(4)	—	(4)
Net income attributable to partners	$ 102	$ 5	$ 107
Six Months Ended June 30, 2013			
Sales of natural gas, propane, NGLs and condensate	$ 1,311	$ 34	$ 1,345
Transportation, processing and other	124	1	125
Gains from commodity derivative activity, net	71	—	71
Total operating revenues	1,506	35	1,541
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	1,159	22	1,181
Operating and maintenance expense	96	2	98
Depreciation and amortization expense	43	1	44
General and administrative expense	32	—	32
Other operating expense	4	—	4
Total operating costs and expenses	1,334	25	1,359
Operating income	172	10	182
Interest expense	(26)	—	(26)
Earnings from unconsolidated affiliates	16	—	16
Income before income taxes	162	10	172
Income tax expense	(1)	—	(1)
Net income	161	10	171
Net income attributable to noncontrolling interests	(7)	—	(7)
Net income attributable to partners	$ 154	$ 10	$ 164

4. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Midstream, LLC. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Services Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf. Except with respect to the annual fee, there is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for expenses and expenditures incurred or payments made on our behalf. The annual fee under the Services Agreement is subject to adjustment based on the scope of general and administrative services performed by DCP Midstream, LLC, as well an annual adjustment based on changes to the Consumer Price Index.

On March 31, 2014, the annual fee payable under the Services Agreement was increased by approximately $15 million, prorated for the remainder of the calendar year, to $44 million. The increase is predominantly attributable to general and administrative expenses previously incurred directly by the Eagle Ford system being reallocated to the Services Agreement in connection with the contribution of the remaining 20% interest in the Eagle Ford system to us, bringing our ownership to 100%.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Services Agreement	$ 12	$ 7	$ 19	$ 14
Other fees — DCP Midstream, LLC	—	4	4	8
Total — DCP Midstream, LLC	$ 12	$ 11	$ 23	$ 22

In addition to the fees paid pursuant to the Services Agreement, we incurred allocated expenses, including insurance and internal audit fees with DCP Midstream, LLC of less than $1 million for the three and six months ended June 30, 2014, and $1 million for the three and six months ended June 30, 2013. The Eagle Ford system incurred $3 million in general and administrative expenses directly from DCP Midstream, LLC for the three months ended June 30, 2013, and $4 million and $7 million in general and administrative expenses directly from DCP Midstream, LLC for the six months ended June 30, 2014 and 2013, respectively, before the reallocation of the Eagle Ford system to the Services Agreement on March 31, 2014.

Other Agreements and Transactions with DCP Midstream, LLC

In conjunction with our acquisition of the Lucerne 1 plant, which is part of our Natural Gas Services segment, we entered into a long-term fee-based processing agreement with DCP Midstream, LLC pursuant to which DCP Midstream, LLC 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 DCP Midstream, LLC at the Lucerne 1 plant.

In addition to agreements with other shippers, the Front Range pipeline, which was placed into service in February 2014, has in place a 15-year transportation agreement, commencing at the pipeline's in-service date, with DCP Midstream, LLC pursuant to which DCP Midstream, LLC has committed to transport minimum throughput volumes at rates defined in Front Range’s tariffs.

In addition to third party agreements, the Sand Hills pipeline has in place 15-year transportation agreements, commencing at the pipeline's in-service date, with DCP Midstream, LLC pursuant to which DCP Midstream, LLC has committed to transport minimum throughput volumes at rates defined in Sand Hills’ tariffs.

In addition to third party agreements, the Southern Hills pipeline has in place a 15-year transportation agreement, commencing at the pipeline's in-service date, with DCP Midstream, LLC pursuant to which DCP Midstream, LLC has committed to transport minimum throughput volumes at rates defined in Southern Hills’ tariffs.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 548	$ 435	$ 1,190	$ 837
Transportation, processing and other	$ 25	$ 11	$ 43	$ 29
Purchases of natural gas, propane and NGLs	$ 32	$ 39	$ 112	$ 94
(Losses) gains from commodity derivative activity, net	$ (11)	$ 67	$ (23)	$ 69
General and administrative expense	$ 12	$ 11	$ 23	$ 22
Spectra Energy:				
Purchases of natural gas, propane and NGLs	$ 22	$ 11	$ 42	$ 29
Transportation, processing and other	$ —	$ —	$ 14	$ —

We had balances with affiliates as follows:

	June 30, 2014	December 31, 2013
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 223	$ 211
Accounts payable	$ 22	$ 37
Unrealized gains on derivative instruments — current	$ 77	$ 79
Unrealized gains on derivative instruments — long-term	$ 40	$ 81
Unrealized losses on derivative instruments — current	$ 9	$ 18
Unrealized losses on derivative instruments — long-term	$ 3	$ 1
Spectra Energy:		
Accounts receivable	$ —	$ 1
Accounts payable	$ 8	$ 6

5. Inventories

Inventories were as follows:

	June 30, 2014	December 31, 2013
	(Millions)	
Natural gas	$ 13	$ 38
NGLs	19	29
Total inventories	$ 32	$ 67

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 no lower of cost or market adjustments during the three months ended June 30, 2014, $3 million in lower of cost or market adjustments during the six months ended June 30, 2014, and $3 million in lower of cost or market adjustments during the three and six months ended June 30, 2013.

6. Property, Plant and Equipment

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

	Depreciable Life	June 30, 2014	December 31, 2013
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$ 2,201	$ 2,205
Processing, storage, and terminal facilities	35 — 60 Years	1,993	1,645
Other	3 — 30 Years	57	49
Construction work in progress		169	310
Property, plant and equipment		4,420	4,209
Accumulated depreciation		(1,213)	(1,163)
Property, plant and equipment, net		$ 3,207	$ 3,046

Interest capitalized on construction projects for the three months ended June 30, 2014 and 2013 was $2 million and $3 million, respectively, and for the six months ended June 30, 2014 and 2013 was $3 million and $5 million, respectively.

Depreciation expense was $26 million and $21 million for the three months ended June 30, 2014 and 2013, respectively, and $50 million and $40 million for the six months ended June 30, 2014, and 2013, respectively.

During the six months ended June 30, 2014 and 2013, we discontinued certain construction projects and wrote off approximately $1 million and $4 million, respectively, in construction work in progress to other expense in the condensed consolidated statements of operations. We had no write-offs during each of the three months ended June 30, 2014 and 2013.

7. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

		Carrying Value as of	
	Percentage Ownership	June 30, 2014	December 31, 2013
		(Millions)	
Sand Hills Pipeline, LLC	33.33%	$ 397	$ —
Discovery Producer Services LLC	40%	390	348
Southern Hills Pipeline, LLC	33.33%	331	—
Front Range Pipeline LLC	33.33%	164	134
Texas Express Pipeline	10%	99	96
Mont Belvieu Enterprise Fractionator	12.5%	25	26
Mont Belvieu 1 Fractionator	20%	14	16
Other	Various	6	7
Total investments in unconsolidated affiliates		$ 1,426	$ 627

There was an excess of the carrying amount of the investment over the underlying equity of Sand Hills of $10 million at June 30, 2014 which is associated with interest capitalized during the construction of the Sand Hills pipeline and is being amortized over the life of the underlying long-lived assets of Sand Hills pipeline.

There was an excess of the carrying amount of the investment over the underlying equity of Southern Hills of $8 million at June 30, 2014 which is associated with interest capitalized during the construction of the Southern Hills pipeline and is being amortized over the life of the underlying long-lived assets of Southern Hills pipeline.

Earnings (losses) from investments in unconsolidated affiliates were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Sand Hills Pipeline, LLC	$ 6	$ —	$ 6	$ —
Mont Belvieu Enterprise Fractionator	4	2	8	6
Southern Hills Pipeline, LLC	4	—	4	—
Mont Belvieu 1 Fractionator	3	5	4	9
Discovery Producer Services LLC	—	1	(1)	1
Front Range Pipeline LLC	(1)	—	(2)	—
Total earnings from unconsolidated affiliates	$ 16	$ 8	$ 19	$ 16

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Statements of operations:				
Operating revenue	$ 208	$ 123	$ 319	$ 231
Operating expenses	$ 132	$ 72	$ 214	$ 139
Net income	$ 76	$ 51	$ 105	$ 92

	June 30, 2014	December 31, 2013
	(Millions)	
Balance sheets:		
Current assets	$ 185	$ 182
Long-term assets	5,091	2,678
Current liabilities	(258)	(276)
Long-term liabilities	(150)	(37)
Net assets	$ 4,868	$ 2,547

8. Fair Value Measurement

Determination of Fair Value

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

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability positions 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 level of judgment involved in the most significant input in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

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

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

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third party pricing services, 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 may use interest rate swap agreements as part of our overall capital strategy. These instruments may 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 long-lived intangible assets. Assets and liabilities acquired in third party 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.

The following table presents the financial instruments carried at fair value as of June 30, 2014 and December 31, 2013, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	June 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$ —	$ 13	$ 65	$ 78	$ —	$ 14	$ 65	$ 79
Short-term investments (b)	$ 50	$ —	$ —	$ 50	$ 9	$ —	$ —	$ 9
Long-term assets (c):								
Commodity derivatives	$ —	$ 4	$ 38	$ 42	$ —	$ 12	$ 75	$ 87
Current liabilities (d):								
Commodity derivatives	$ —	$ (17)	$ —	$ (17)	$ —	$ (26)	$ —	$ (26)
Interest rate derivatives	$ —	$ —	$ —	$ —	$ —	$ (2)	$ —	$ (2)
Long-term liabilities (e):								
Commodity derivatives	$ —	$ (6)	$ —	$ (6)	$ —	$ (1)	$ —	$ (1)

(a) Included in current unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(b) Includes short-term money market securities included in cash and cash equivalents in our condensed consolidated balance sheets.
(c) Included in long-term unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our condensed consolidated balance sheets.
(e) 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 would be reflected in a table as Transfers into/out of Level 1/Level 2. During the three and six months ended June 30, 2014 and 2013, there were no transfers into/out of 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 condensed 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” captions.

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended June 30, 2014 (a):				
Beginning balance	$ 70	$ 60	$ (1)	$ —
Net realized and unrealized gains (losses) included in earnings (c)	13	(22)	—	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(18)	—	1	—
Purchases	—	—	—	—
Ending balance	$ 65	$ 38	$ —	$ —
Net unrealized gains (losses) on derivatives still held included in earnings (c)	$ 13	$ (22)	$ —	$ —
Three months ended June 30, 2013 (a):				
Beginning balance	$ 61	$ 122	$ —	$ —
Net realized and unrealized gains included in earnings (c)	45	16	—	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(19)	—	—	—
Ending balance	$ 87	$ 138	$ —	$ —
Net unrealized gains on derivatives still held included in earnings (c)	$ 41	$ 16	$ —	$ —

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Six months ended June 30, 2014 (a):				
Beginning balance	$ 65	$ 75	$ —	$ —
Net realized and unrealized gains (losses) included in earnings (c)	29	(37)	—	—
Transfers into Level 3 (b)	—	—	—	
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(29)	—	—	—
Purchases	—	—	—	—
Ending balance	$ 65	$ 38	$ —	$ —
Net unrealized gains (losses) on derivatives still held included in earnings (c)	$ 31	$ (37)	$ —	$ —
Six months ended June 30, 2013 (a):				
Beginning balance	$ 40	$ 65	$ (1)	$ —
Net realized and unrealized gains included in earnings (c)	46	11	—	—
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	—	—	—
Settlements	(23)	—	1	—
Purchases	24	62	—	—
Ending balance	$ 87	$ 138	$ —	$ —
Net unrealized gains on derivatives still held included in earnings (c)	$ 43	$ 11	$ —	$ —

(a) There were no issuances or sales of derivatives for the three and six months ended June 30, 2014 and 2013.
(b) Amounts transferred into/out of Level 3 would be 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.

	June 30, 2014		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$ 103	$0.28-$2.20	Per gallon

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, if applicable, 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, if applicable, 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 specific 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, accounts payable and short-term borrowings 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.

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.

	June 30, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(Millions)			
Senior Notes				
3.25% Senior Notes	$ 250	$ 257	$ 250	$ 258
2.50% Senior Notes	498	514	497	500
2.70% Senior Notes	323	330	—	—
4.95% Senior Notes	349	384	349	354
3.875% Senior Notes	494	505	494	461
5.60% Senior Notes	396	441	—	—

9. Debt

	June 30, 2014	December 31, 2013
	(Millions)	
Commercial Paper		
Short-term borrowings, weighted-average interest rate of 1.14% as of December 31, 2013	$ —	$ 335
Debt Securities		
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250	250
Issued November 27, 2012, interest at 2.50% payable semi-annually, due December 1, 2017	500	500
Issued March 13, 2014, interest at 2.70% payable semi-annually, due April 1, 2019	325	—
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350	350
Issued March 14, 2013, interest at 3.875% payable semi-annually, due March 15, 2023	500	500
Issued March 13, 2014, interest at 5.60% payable semi-annually, due April 1, 2044	400	—
Unamortized discount	(15)	(10)
Total debt	2,310	1,925
Short-term borrowings	—	(335)
Total long-term debt	$ 2,310	$ 1,590

Commercial Paper Program

We have a commercial paper program, or the Commercial Paper Program, under which we may issue unsecured commercial paper notes. Amounts available under this program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of notes outstanding, combined with the amount outstanding under our Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. As of June 30, 2014, we had no commercial paper outstanding.

Amended and Restated Credit Agreement

On May 1, 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement replaced our previous Credit Agreement dated as of November 10, 2011, which had a total borrowing capacity of $1 billion and would have matured on November 10, 2016. The Amended and Restated Credit Agreement will be used for working capital requirements and other general partnership purposes including acquisitions.

Indebtedness under the Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.275% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.275% based on our current credit rating. The Amended and Restated Credit Agreement incurs an annual facility fee of 0.225% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion Amended and Restated Credit Agreement.

As of June 30, 2014, the unused capacity under the Amended and Restated Credit Agreement was $1,249 million, which is net of letters of credit. Our borrowing capacity may be limited by the Amended and Restated Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under our Amended and Restated Credit Agreement will not become due prior to the May 1, 2019 maturity date.

Debt Securities

In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million and $392 million, respectively, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the March 2014 Transactions. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, unless redeemed prior to maturity.

In March 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 of $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 is 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 notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Amended and Restated 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. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

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

	Debt Maturities
	(Millions)
2015	$ 250
2016	—
2017	500
2018	—
2019	325
Thereafter	1,250
	2,325
Unamortized discount	(15)
Total	$ 2,310

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 either physical or 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 composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following 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 significant portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2017 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 2014 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 construction or expansion of our storage caverns, we may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when we bring the storage caverns to operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase the base gas, the deferred losses or gains would remain in accumulated other comprehensive income, or AOCI, until the cavern is emptied and the base gas is sold. The balance in AOCI of our previously settled base gas cash flow hedges was in a loss position of $6 million as of June 30, 2014.

Interest Rate Risk

Prior to June 30, 2014, we had interest rate swap agreements with notional values totaling $150 million, which were accounted for under the mark-to-market method of accounting and repriced prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we paid fixed-rates ranging from 2.94% to 2.99%, and received interest payments based on the one-month LIBOR. These interest rate swap agreements settled in June 2014. 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. In conjunction with the issuance of 14,375,000 of our common units to the public in March 2014, we paid down a portion of the balance outstanding under our Commercial Paper Program and reclassified the remaining loss of $1 million in AOCI into earnings as interest expense.

In conjunction with the issuance of our 4.95% Senior Notes in March 2012, we entered into forward-starting interest rate swap agreements to reduce our exposure to market rate fluctuations prior to issuance. These derivative financial instruments were designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixed the rate we would pay on a portion of our 4.95% Senior Notes, the deferred loss in AOCI will be amortized into interest expense through the maturity of the notes in 2022. The balance in AOCI of these cash flow hedges was in a loss position of $4 million as of June 30, 2014.

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 Swaps and Derivatives 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 Amended and Restated 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 were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties would 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 other credit arrangements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Amended and Restated Credit Agreement. As of June 30, 2014, we were not a party to any agreements that would trigger the cross-default provisions.

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

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of June 30, 2014, 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 June 30, 2014, if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of June 30, 2014, 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 $11 million.

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, and designated as cash flow hedges, we include the impact to AOCI on our condensed 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 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
	June 30, 2014			December 31, 2013		
	(Millions)					
Assets:						
Commodity derivatives	$ 120	$ (10)	$ 110	$ 166	$ (13)	$ 153
Liabilities:						
Commodity derivatives	$ (23)	$ 10	$ (13)	$ (27)	$ 13	$ (14)
Interest rate derivatives	$ —	$ —	$ —	$ (2)	$ —	$ (2)

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

Summarized Derivative Information

The fair value of our derivative instruments that are marked-to-market each period, as well as the location of each within our condensed consolidated balance sheets, by major category, is summarized below. We have no derivative instruments that are designated as hedging instruments for accounting purposes as of June 30, 2014 and December 31, 2013.

Balance Sheet Line Item	June 30, 2014	December 31, 2013	Balance Sheet Line Item	June 30, 2014	December 31, 2013
	(Millions)			(Millions)	
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ 78	$ 79	Unrealized losses on derivative instruments — current	$ (17)	$ (26)
Unrealized gains on derivative instruments — long-term	42	87	Unrealized losses on derivative instruments — long-term	(6)	(1)
	$ 120	$ 166		$ (23)	$ (27)
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments — current	$ —	$ —	Unrealized losses on derivative instruments — current	$ —	$ (2)
Unrealized gains on derivative instruments — long-term	—	—	Unrealized losses on derivative instruments — long-term	—	—
	$ —	$ —		$ —	$ (2)

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the three months ended June 30, 2014:

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
			(Millions)		
Net deferred (losses) gains in AOCI (beginning balance)	$ (4)		$ (6)	$ 1	$ (9)
Losses reclassified from AOCI to earnings — effective portion	—	(b) (c)	—	—	—
Net deferred (losses) gains in AOCI (ending balance)	$ (4)		$ (6)	$ 1	$ (9)

(a) Relates to Discovery, our unconsolidated affiliate.
(b) Included in interest expense in our condensed consolidated statements of operations.
(c) For the three months ended June 30, 2014, no derivative losses were reclassified from AOCI to interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the six months ended June 30, 2014:

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
	(Millions)				
Net deferred (losses) gains in AOCI (beginning balance)	$ (6)		$ (6)	$ 1	$ (11)
Losses reclassified from AOCI to earnings — effective portion	2	(b) (c)	—	—	2
Net deferred (losses) gains in AOCI (ending balance)	$ (4)		$ (6)	$ 1	$ (9)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ (1)		$ —	$ —	$ (1)

(a) Relates to Discovery, our unconsolidated affiliate.
(b) Included in interest expense in our condensed consolidated statements of operations.
(c) For the six months ended June 30, 2014, $1 million of derivative losses were reclassified from AOCI to interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

For the three and six months ended June 30, 2014, no derivative losses attributable to the ineffective portion and amount excluded from effectiveness testing was recognized in gains or losses from commodity derivative activity, net and 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 three months ended June 30, 2013:

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
	(Millions)				
Net deferred losses in AOCI (beginning balance)	$ (9)		$ (5)	$ —	$ (14)
Losses reclassified from AOCI to earnings — effective portion	$ 1	(b)	$ —	$ —	$ 1
Net deferred losses in AOCI (ending balance)	$ (8)		$ (5)	$ —	$ (13)

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

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
	(Millions)				
Net deferred (losses) gains in AOCI (beginning balance)	$ (10)		$ (6)	$ 1	$ (15)
Losses (gains) recognized in AOCI on derivatives - effective portion	—		1	(1)	—
Losses reclassified from AOCI to earnings — effective portion	$ 2	(b)	$ —	$ —	$ 2
Net deferred losses in AOCI (ending balance)	$ (8)		$ (5)	$ —	$ (13)

(a) Relates to Discovery, our unconsolidated affiliate.

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

For the six months ended June 30, 2013, less than $1 million of derivative losses attributable to the ineffective portion and amount excluded from effectiveness testing was recognized in gains or losses from commodity derivative activity, net and interest expense in our condensed consolidated statements of operations. For the six months ended June 30, 2013, 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.

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

Commodity Derivatives: Statements of Operations Line Item	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(Millions)			
Third party:				
Realized losses	$ (2)	$ (3)	$ (5)	$ (7)
Unrealized (losses) gains	(9)	7	(9)	9
(Losses) gains from commodity derivative activity, net	$ (11)	$ 4	$ (14)	$ 2
Affiliates:				
Realized gains	$ 10	$ 16	$ 11	$ 30
Unrealized (losses) gains	(21)	51	(34)	39
(Losses) gains from commodity derivative activity, net —affiliates	$ (11)	$ 67	$ (23)	$ 69

Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(Millions)			
Third party:				
Realized losses	$ (1)	$ (1)	$ (2)	$ (1)
Unrealized gains	1	1	2	1
Interest expense	$ —	$ —	$ —	$ —

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

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

	June 30, 2014			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long (Short) Position (MMbtu)
2014	(348,312)	(5,434,092)	(3,115,936)	3,272,500
2015	(745,695)	(13,458,975)	(5,711,570)	1,285,000
2016	(561,922)	(3,668,564)	(813,267)	(2,140,000)
2017	—	(6,387,500)	—	—

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

11. Partnership Equity and Distributions

In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement will allow us to issue additional common units from time to time, which we intend to conduct under an equity distribution agreement with one or more financial institutions in the future. As of June 30, 2014, we have issued no securities under this registration statement.

In March 2014, we issued 14,375,000 common units to the public at $48.90 per unit. We received proceeds of $677 million, net of offering costs.

In March 2014, we issued 4,497,158 common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions.

In June 2013, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $300 million, which became effective on June 27, 2013. The shelf registration statement allows us to issue additional common units. In November 2013, we entered into an equity distribution agreement, or the 2013 equity distribution agreement, with a group of financial institutions as sales agents. The agreement provides for the offer and sale from time to time, through our sales agents, of common units having an aggregate offering amount of up to $300 million. During the six months ended June 30, 2014, we issued 2,011,000 common units pursuant to the 2013 equity distribution agreement and received proceeds of $110 million, which is net of commissions and offering costs of $1 million. The proceeds were used to finance growth opportunities and for general partnership purposes. As of June 30, 2014, approximately $101 million of the aggregate offering amount remains available for sale pursuant to the 2013 equity distribution agreement.

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

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

In August 2011, we entered into an equity distribution agreement with a financial institution, as sales agent. The agreement provides for the offer and sale from time to time, through our sales agent, of common units having an aggregate offering amount of up to $150 million. During the six months ended June 30, 2013, we issued 1,408,547 of our common units pursuant to this equity distribution agreement and received proceeds of $67 million, net of commissions and accrued offering costs of $2 million, which were used to finance growth opportunities and for general partnership purposes. As of June 30, 2014, no common units remain available for sale pursuant to this equity distribution agreement.

The following table presents our cash distributions paid in 2014 and 2013:

Payment Date	Per Unit Distribution	Total Cash Distribution
		(Millions)
May 15, 2014	$ 0.7450	$ 106
February 14, 2014	$ 0.7325	$ 86
November 14, 2013	$ 0.7200	$ 82
August 14, 2013	$ 0.7100	$ 72
May 15, 2013	$ 0.7000	$ 69
February 14, 2013	$ 0.6900	$ 54

12. Net Income or Loss per Limited Partner Unit

Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per LPU is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding Performance Units, Phantom Units and Restricted Units. The dilutive effect of unit-based awards was 12,667 and 20,370 equivalent units during the three months ended June 30, 2014 and 2013, respectively, and 11,213, and 22,751 equivalent units during the six months ended June 30, 2014, and 2013, respectively.

13. Commitments and Contingent Liabilities

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

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities incorporates compliance with environmental laws and regulations and safety standards. In addition, there is increasing focus, from city, state and federal regulatory officials and through litigation, on hydraulic fracturing and the real or perceived environmental impacts of this technique, which indirectly presents some risk to our available supply of natural gas. Failure to comply with these various health, safety and environmental laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

14. Business Segments

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

Natural Gas Services — Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, transporting and storing natural gas, and fractionating NGLs.

NGL Logistics — Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs.

Wholesale Propane Logistics — Our Wholesale Propane Logistics segment provides services that include the receipt of propane by pipeline, rail or ship to our terminals that store and deliver the product to distributors.

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

The following tables set forth our segment information:

Three Months Ended June 30, 2014:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 732	$ 20	$ 60	$ —	$ 812
Gross margin (a)	$ 115	$ 20	$ 1	—	$ 136
Operating and maintenance expense	(49)	(4)	(3)	—	(56)
Depreciation and amortization expense	(26)	(2)	—	—	(28)
General and administrative expense	—	—	—	(15)	(15)
Earnings from unconsolidated affiliates	—	16	—	—	16
Interest expense	—	—	—	(23)	(23)
Income tax expense	—	—	—	(1)	(1)
Net income (loss)	$ 40	$ 30	$ (2)	$ (39)	$ 29
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income (loss) attributable to partners	$ 40	$ 30	$ (2)	$ (39)	$ 29
Non-cash derivative mark-to-market (b)	$ (30)	$ —	$ —	$ 1	$ (29)

Three Months Ended June 30, 2013:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 720	$ 19	$ 53	$ —	$ 792
Gross margin (a)	$ 184	$ 19	$ 5	—	$ 208
Operating and maintenance expense	(44)	(4)	(4)	—	(52)
Depreciation and amortization expense	(21)	(2)	—	—	(23)
General and administrative expense	—	—	—	(16)	(16)
Earnings from unconsolidated affiliates	1	7	—	—	8
Interest expense	—	—	—	(14)	(14)
Net income (loss)	$ 120	$ 20	$ 1	$ (30)	$ 111
Net income attributable to noncontrolling interests	(4)	—	—	—	(4)
Net income (loss) attributable to partners	$ 116	$ 20	$ 1	$ (30)	$ 107
Non-cash derivative mark-to-market (b)	$ 58	$ —	$ —	$ —	$ 58
Non-cash lower of cost or market adjustments	$ 2	$ —	$ 1	$ —	$ 3

Six Months Ended June 30, 2014:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 1,581	$ 37	$ 275	$ —	$ 1,893
Gross margin (a)	$ 279	$ 37	$ 16	—	$ 332
Operating and maintenance expense	(87)	(8)	(6)	—	(101)
Depreciation and amortization expense	(50)	(3)	(1)	—	(54)
General and administrative expense	—	—	—	(31)	(31)
Other expense	(1)	—	—	—	(1)
(Losses) earnings from unconsolidated affiliates	(1)	20	—	—	19
Interest expense	—	—	—	(42)	(42)
Income tax expense	—	—	—	(4)	(4)
Net income (loss)	$ 140	$ 46	$ 9	$ (77)	$ 118
Net income attributable to noncontrolling interests	(10)	—	—	—	(10)
Net income (loss) attributable to partners	$ 130	$ 46	$ 9	$ (77)	$ 108
Non-cash derivative mark-to-market (b)	$ (42)	$ —	$ (1)	$ —	$ (43)
Non-cash lower of cost or market adjustments	$ —	$ —	$ 3	$ —	$ 3
Capital expenditures	$ 130	$ 14	$ 7	$ —	$ 151
Acquisition expenditures	$ 102	$ 669	$ —	$ —	$ 771
Investments in unconsolidated affiliates	$ 48	$ 45	$ —	$ —	$ 93

Six Months Ended June 30, 2013:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 1,295	$ 38	$ 208	$ —	$ 1,541
Gross margin (a)	$ 289	$ 38	$ 33	$ —	$ 360
Operating and maintenance expense	(83)	(8)	(7)	—	(98)
Depreciation and amortization expense	(40)	(3)	(1)	—	(44)
General and administrative expense	—	—	—	(32)	(32)
Other expense	—	—	(4)	—	(4)
Earnings from unconsolidated affiliates	1	15	—	—	16
Interest expense	—	—	—	(26)	(26)
Income tax expense	—	—	—	(1)	(1)
Net income (loss)	$ 167	$ 42	$ 21	$ (59)	$ 171
Net income attributable to noncontrolling interests	(7)	—	—	—	(7)
Net income (loss) attributable to partners	$ 160	$ 42	$ 21	$ (59)	$ 164
Non-cash derivative mark-to-market (b)	$ 49	$ —	$ (1)	$ —	$ 48
Non-cash lower of cost or market adjustments	$ 2	$ —	$ 1	$ —	$ 3
Capital expenditures	$ 190	$ 4	$ 1	$ —	$ 195
Acquisitions, net of cash acquired	$ 486	$ —	$ —	$ —	$ 486
Investments in unconsolidated affiliates	$ 44	$ 43	$ —	$ —	$ 87

	June 30, 2014	December 31, 2013
	(Millions)	
Segment long-term assets:		
Natural Gas Services (c)	$ 3,484	$ 3,303
NGL Logistics	1,327	555
Wholesale Propane Logistics	110	106
Other (d)	61	100
Total long-term assets	4,982	4,064
Current assets (c)	486	503
Total assets	$ 5,468	$ 4,567

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

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

(c) The segment information for the six months ended June 30, 2014, three and six months ended June 30, 2013, and as of December 31, 2013 includes the results of our Lucerne 1 plant. The segment information for the three and six months ended June 30, 2013 also includes the results of an 80% interest in the Eagle Ford system. 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 are retrospectively adjusted to furnish comparative information, similar to the pooling method.

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

15. Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2014	2013
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 30	$ 17
Cash paid for income taxes, net of income tax refunds	$ 2	$ 1
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$ 34	$ 28
Other non-cash additions of property, plant and equipment	$ —	$ 1
Non-cash addition of investment in unconsolidated affiliates and property, plant and equipment acquired in March 2014 Transactions	$ 70	$ —
Non-cash excess purchase price in March 2014 Transactions and March 2013 Eagle Ford system transaction	$ 155	$ 125
Accounts payable related to equity issuance costs	$ —	$ 2

16. Supplementary Information — Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a 100% owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP’s results on a consolidated basis. In conjunction with the universal shelf registration statement on Form S-3 which became effective on June 14, 2012, the parent guarantor has agreed to fully and unconditionally guarantee debt securities of the subsidiary issuer. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheet
June 30, 2014

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 50	$ 7	$ —	$ 57
Accounts receivable, net	—	—	317	—	317
Inventories	—	—	32	—	32
Other	—	—	80	—	80
Total current assets	—	50	436	—	486
Property, plant and equipment, net	—	—	3,207	—	3,207
Goodwill and intangible assets, net	—	—	278	—	278
Advances receivable — consolidated subsidiaries	2,623	1,979	—	(4,602)	—
Investments in consolidated subsidiaries	76	360	—	(436)	—
Investments in unconsolidated affiliates	—	—	1,426	—	1,426
Other long-term assets	—	19	52	—	71
Total assets	$ 2,699	$ 2,408	$ 5,399	$ (5,038)	$ 5,468
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 22	$ 357	$ —	$ 379
Advances payable — consolidated subsidiaries	—	—	4,602	(4,602)	—
Long-term debt	—	2,310	—	—	2,310
Other long-term liabilities	—	—	48	—	48
Total liabilities	—	2,332	5,007	(4,602)	2,737
Commitments and contingent liabilities					
Equity:					
Partners’ equity:					
Net equity	2,699	80	365	(436)	2,708
Accumulated other comprehensive loss	—	(4)	(5)	—	(9)
Total partners’ equity	2,699	76	360	(436)	2,699
Noncontrolling interests	—	—	32	—	32
Total equity	2,699	76	392	(436)	2,731
Total liabilities and equity	$ 2,699	$ 2,408	$ 5,399	$ (5,038)	$ 5,468

	Condensed Consolidating Balance Sheet December 31, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ —	$ 12	$ —	$ 12
Accounts receivable, net	—	—	342	—	342
Inventories	—	—	67	—	67
Other	—	—	82	—	82
Total current assets	—	—	503	—	503
Property, plant and equipment, net	—	—	3,046	—	3,046
Goodwill and intangible assets, net	—	—	283	—	283
Advances receivable — consolidated subsidiaries	1,805	1,683	—	(3,488)	—
Investments in consolidated subsidiaries	181	426	—	(607)	—
Investments in unconsolidated affiliates	—	—	627	—	627
Other long-term assets	—	12	96	—	108
Total assets	$ 1,986	$ 2,121	$ 4,555	$ (4,095)	$ 4,567
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ 1	$ 350	$ 372	$ —	$ 723
Advances payable — consolidated subsidiaries	—	—	3,488	(3,488)	—
Long-term debt	—	1,590	—	—	1,590
Other long-term liabilities	—	—	41	—	41
Total liabilities	1	1,940	3,901	(3,488)	2,354
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Predecessor equity	—	—	40	—	40
Net equity	1,985	187	391	(607)	1,956
Accumulated other comprehensive loss	—	(6)	(5)	—	(11)
Total partners' equity	1,985	181	426	(607)	1,985
Noncontrolling interests	—	—	228	—	228
Total equity	1,985	181	654	(607)	2,213
Total liabilities and equity	$ 1,986	$ 2,121	$ 4,555	$ (4,095)	$ 4,567

(a) The financial information as of December 31, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system, transfers of net assets between entities under common control that were accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2014

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 754	$ —	$ 754
Transportation, processing and other	—	—	80	—	80
Losses from commodity derivative activity, net	—	—	(22)	—	(22)
Total operating revenues	—	—	812	—	812
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	676	—	676
Operating and maintenance expense	—	—	56	—	56
Depreciation and amortization expense	—	—	28	—	28
General and administrative expense	—	—	15	—	15
Total operating costs and expenses	—	—	775	—	775
Operating income	—	—	37	—	37
Interest expense, net	—	(23)	—	—	(23)
Income from consolidated subsidiaries	29	52	—	(81)	—
Earnings from unconsolidated affiliates	—	—	16	—	16
Income before income taxes	29	29	53	(81)	30
Income tax expense	—	—	(1)	—	(1)
Net income	29	29	52	(81)	29
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income attributable to partners	$ 29	$ 29	$ 52	$ (81)	$ 29

Condensed Consolidating Statement of Comprehensive Income
Three Months Ended June 30, 2014

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 29	$ 29	$ 52	$ (81)	$ 29
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	—	—	—	—
Other comprehensive income from consolidated subsidiaries	—	—	—	—	—
Total other comprehensive income	—	—	—	—	—
Total comprehensive income	29	29	52	(81)	29
Total comprehensive income attributable to noncontrolling interests	—	—	—	—	—
Total comprehensive income attributable to partners	$ 29	$ 29	$ 52	$ (81)	$ 29

	Condensed Consolidating Statement of Operations Three Months Ended June 30, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 660	$ —	$ 660
Transportation, processing and other	—	—	61	—	61
Gains from commodity derivative activity, net	—	—	71	—	71
Total operating revenues	—	—	792	—	792
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	584	—	584
Operating and maintenance expense	—	—	52	—	52
Depreciation and amortization expense	—	—	23	—	23
General and administrative expense	—	—	16	—	16
Total operating costs and expenses	—	—	675	—	675
Operating income	—	—	117	—	117
Interest expense, net	—	(14)	—	—	(14)
Income from consolidated subsidiaries	107	121	—	(228)	—
Earnings from unconsolidated affiliates	—	—	8	—	8
Income before income taxes	107	107	125	(228)	111
Income tax expense	—	—	—	—	—
Net income	107	107	125	(228)	111
Net income attributable to noncontrolling interests	—	—	(4)	—	(4)
Net income attributable to partners	$ 107	$ 107	$ 121	$ (228)	$ 107

(a) The financial information for the three months ended June 30, 2013 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Comprehensive Income Three Months Ended June 30, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$ 107	$ 107	$ 125	$ (228)	$ 111
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	1	—	—	1
Other comprehensive income from consolidated subsidiaries	1	—	—	(1)	—
Total other comprehensive income	1	1	—	(1)	1
Total comprehensive income	108	108	125	(229)	112
Total comprehensive income attributable to noncontrolling interests	—	—	(4)	—	(4)
Total comprehensive income attributable to partners	$ 108	$ 108	$ 121	$ (229)	$ 108

(a) The financial information for the three months ended June 30, 2013 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Operations Six Months Ended June 30, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,767	$ —	$ 1,767
Transportation, processing and other	—	—	163	—	163
Gains from commodity derivative activity, net	—	—	(37)	—	(37)
Total operating revenues	—	—	1,893	—	1,893
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	1,561	—	1,561
Operating and maintenance expense	—	—	101	—	101
Depreciation and amortization expense	—	—	54	—	54
General and administrative expense	—	—	31	—	31
Other expense	—	—	1	—	1
Total operating costs and expenses	—	—	1,748	—	1,748
Operating income	—	—	145	—	145
Interest expense, net	—	(42)	—	—	(42)
Income from consolidated subsidiaries	108	150	—	(258)	—
Earnings from unconsolidated affiliates	—	—	19	—	19
Income before income taxes	108	108	164	(258)	122
Income tax expense	—	—	(4)	—	(4)
Net income	108	108	160	(258)	118
Net income attributable to noncontrolling interests	—	—	(10)	—	(10)
Net income attributable to partners	$ 108	$ 108	$ 150	$ (258)	$ 108

(a) The financial information for the six months ended June 30, 2014 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Comprehensive Income Six Months Ended June 30, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$ 108	$ 108	$ 160	$ (258)	$ 118
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	2	—	—	2
Other comprehensive income from consolidated subsidiaries	2	—	—	(2)	—
Total other comprehensive income	2	2	—	(2)	2
Total comprehensive income	110	110	160	(260)	120
Total comprehensive income attributable to noncontrolling interests	—	—	(10)	—	(10)
Total comprehensive income attributable to partners	$ 110	$ 110	$ 150	$ (260)	$ 110

(a) The financial information for the six months ended June 30, 2014 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Operations Six Months Ended June 30, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,345	$ —	$ 1,345
Transportation, processing and other	—	—	125	—	125
Gains from commodity derivative activity, net	—	—	71	—	71
Total operating revenues	—	—	1,541	—	1,541
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	1,181	—	1,181
Operating and maintenance expense	—	—	98	—	98
Depreciation and amortization expense	—	—	44	—	44
General and administrative expense	—	—	32	—	32
Other expense	—	—	4	—	4
Total operating costs and expenses	—	—	1,359	—	1,359
Operating income	—	—	182	—	182
Interest expense	—	(26)	—	—	(26)
Earnings from unconsolidated affiliates	—	—	16	—	16
Income from consolidated subsidiaries	164	190	—	(354)	—
Income before income taxes	164	164	198	(354)	172
Income tax expense	—	—	(1)	—	(1)
Net income	164	164	197	(354)	171
Net income attributable to noncontrolling interests	—	—	(7)	—	(7)
Net income attributable to partners	$ 164	$ 164	$ 190	$ (354)	$ 164

(a) The financial information for the six months ended June 30, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system. 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 are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Comprehensive Income Six Months Ended June 30, 2013 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$ 164	$ 164	$ 197	$ (354)	$ 171
Other comprehensive loss:					
Reclassification of cash flow hedge losses into earnings	—	2	—	—	2
Other comprehensive income from consolidated subsidiaries	2	—	—	(2)	—
Total other comprehensive income	2	2	—	(2)	2
Total comprehensive income	166	166	197	(356)	173
Total comprehensive income attributable to noncontrolling interests	—	—	(7)	—	(7)
Total comprehensive income attributable to partners	$ 166	$ 166	$ 190	$ (356)	$ 166

(a) The financial information for the six months ended June 30, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system. 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 are retrospectively adjusted to furnish comparative information similar to the pooling method.

	Condensed Consolidating Statement of Cash Flows Six Months Ended June 30, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	—	(29)	329	—	300
INVESTING ACTIVITIES:					
Intercompany transfers	(595)	(296)	—	891	—
Capital expenditures	—	—	(151)	—	(151)
Acquisitions, net of cash acquired	—	—	(102)	—	(102)
Acquisition of unconsolidated affiliates	—	—	(669)	—	(669)
Investments in unconsolidated affiliates	—	—	(93)	—	(93)
Proceeds from sales of assets	—	—	17	—	17
Net cash used in investing activities	(595)	(296)	(998)	891	(998)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	891	(891)	—
Proceeds from long-term debt	—	719	—	—	719
Payments of commercial paper, net	—	(335)	—	—	(335)
Payments of deferred financing costs	—	(9)	—	—	(9)
Excess purchase price over acquired interests and commodity hedges	—	—	(15)	—	(15)
Proceeds from issuance of common units, net of offering costs	787	—	—	—	787
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(6)	—	(6)
Distributions to limited partners and general partner	(192)	—	—	—	(192)
Distributions to noncontrolling interests	—	—	(11)	—	(11)
Purchase of additional interest in a subsidiary	—	—	(198)	—	(198)
Contributions from noncontrolling interests	—	—	3	—	3
Net cash provided by financing activities	595	375	664	(891)	743
Net change in cash and cash equivalents	—	50	(5)	—	45
Cash and cash equivalents, beginning of period	—	—	12	—	12
Cash and cash equivalents, end of period	—	50	7	—	57

(a) The financial information for the six months ended June 30, 2014 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

Condensed Consolidating Statements of Cash Flows
Six Months Ended June 30, 2013 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (19)	$ 298	$ 2	$ 281
INVESTING ACTIVITIES:					
Intercompany transfers	(440)	(91)	—	531	—
Capital expenditures	—	—	(195)	—	(195)
Acquisitions, net of cash acquired	—	—	(486)	—	(486)
Investments in unconsolidated affiliates	—	—	(87)	—	(87)
Net cash used in investing activities	(440)	(91)	(768)	531	(768)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	531	(531)	—
Proceeds from long-term debt	—	1,079	—	—	1,079
Payments of long-term debt	—	(960)	—	—	(960)
Payment of deferred financing costs	—	(4)	—	—	(4)
Proceeds from issuance of common units, net of offering costs	563	—	—	—	563
Excess purchase price over acquired assets	—	—	(101)	—	(101)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	21	—	21
Distributions to common unitholders and general partner	(123)	—	—	—	(123)
Distributions to noncontrolling interests	—	—	(10)	—	(10)
Contributions from noncontrolling interests	—	—	31	—	31
Distributions to DCP Midstream, LLC	—	—	(3)	—	(3)
Contributions from DCP Midstream, LLC	—	—	1	—	1
Net cash provided by financing activities	440	115	470	(531)	494
Net change in cash and cash equivalents	—	5	—	2	7
Cash and cash equivalents, beginning of period	—	3	2	(3)	2
Cash and cash equivalents, end of period	$ —	$ 8	$ 2	$ (1)	$ 9

(a) The financial information during the six months ended June 30, 2013 includes the results of our Lucerne 1 plant and an 80% interest in the Eagle Ford system. 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 are retrospectively adjusted to furnish comparative information similar to the pooling method.

The parent guarantor, subsidiary issuer and non-guarantor subsidiaries participate in a cash pooling program, whereby cash balances are generally swept daily between the parent guarantor and the non-guarantor subsidiaries bank accounts and those of the subsidiary issuer.

Subsequent to the issuance of the 2013 financial statements, management determined that intercompany transfers between the parent guarantor and the non-guarantor subsidiaries, as well as the subsidiary issuer and the non-guarantor subsidiaries, should be classified as investing activities by the parent guarantor and subsidiary issuer and financing activities by the non-guarantor subsidiaries, within the condensed consolidating statements of cash flows. The intercompany transfers had previously been reported as operating activities by the parent guarantor, subsidiary issuer and non-guarantor subsidiaries. The classification of these intercompany transfers has been corrected in the condensed consolidating financial statements for the six months ended June 30, 2013. This correction has no impact on the consolidated statement of cash flows for all periods presented. These amounts have been included within the line item “intercompany transfers” in investing and financing activities within the condensed consolidating statements of cash flows. The changes to the previously reported amounts are summarized as follows:

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Six Months Ended June 30, 2013					
Net cash provided by (used in) operating activities	$ 440	$ 91	$ (531)	$ —	$ —
Net cash used in investing activities	$ (440)	$ (91)	$ —	$ 531	$ —
Net cash provided by financing activities	$ —	$ —	$ 531	$ (531)	$ —

17. Subsequent Events

On July 28, 2014, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.7575 per unit. The distribution will be payable on August 14, 2014 to unitholders of record on August 8, 2014.

In July 2014, we issued 527,000 common units pursuant to the 2013 equity distribution agreement and received proceeds of $30 million, net of commissions and offering costs of less than $1 million. As of July 31, 2014, approximately $71 million of the aggregate offering amount remains available for sale pursuant to the 2013 equity distribution agreement.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included as Exhibit 99.3 in our Current Report on Form 8-K filed with the SEC on June 13, 2014.

Overview

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

Our business is impacted by commodity prices, which we significantly mitigate on an overall Partnership basis through a multi-year hedging program on volumes of throughput and sales of natural gas, NGLs and condensate. Various factors impact both commodity prices and volumes. Commodity prices historically have been volatile and continue to be volatile.

If commodity prices are weak for a sustained period, our natural gas throughput volumes may be impacted, particularly if producers were to shut in gas. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains firm in areas with liquids rich gas. Drilling remains weak in certain areas with dry gas where relatively lower commodity prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic natural gas production. We use direct NGL hedges to mitigate a significant portion of our NGL price exposure; however, weakening of the relationship of natural gas liquids to crude oil prices does modestly impact the effectiveness of our hedging program to mitigate our exposure to price fluctuations where we use crude oil to hedge our NGL price exposure.

Our highly hedged commodity position mitigates a significant portion of our natural gas, NGL, and condensate commodity price risk through 2017. Additionally, our fee-based business represents a significant portion of our estimated margins.

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

U.S. financial markets and many businesses and investors continue to monitor global conditions. Uncertainty may contribute to volatility in financial and commodity markets.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low historical costs have enabled us to continue executing our multi-faceted growth strategy. Our multi-faceted growth strategy may take numerous forms such as dropdown opportunities from DCP Midstream, LLC, joint venture opportunities, organic build opportunities within our footprint and third-party acquisitions. Dropdowns from DCP Midstream, LLC since the beginning of 2013 have totaled over $2 billion. Throughout the remainder of 2014, we will continue executing our multi-faceted growth strategy.

Some of our recent growth projects include the following:

- The Eagle Ford system completed construction of the Goliad 200 MMcf/d natural gas processing plant which was placed into service in February 2014.
- The Front Range pipeline, of which we own a 33.33% equity interest, was placed into service in February 2014.
- The O'Connor plant expansion to 160 MMcf/d was placed into service in March 2014.
- In March 2014, DCP Midstream, LLC contributed to us the Sand Hills pipeline, the Southern Hills pipeline and the remaining 20% interest in the Eagle Ford system, and we acquired from DCP Midstream, LLC the Lucerne 1 plant and the Lucerne 2 plant, which is currently under construction. These transactions are collectively referred to as the March 2014 Transactions.

- Our expansion plan for Discovery's Keathley Canyon natural gas gathering pipeline system is progressing and is expected to be completed in the fourth quarter of 2014.
- The construction of our Lucerne 2 plant is progressing on schedule and is expected to be completed in mid-2015.

Our capital markets execution has positioned us well in terms of both liquidity and cost of capital to execute our growth plans, including dropdown opportunities with DCP Midstream, LLC. During the six months ended June 30, 2014, we received net proceeds of $787 million from the issuance of our common units to the public and $712 million through public debt offerings of 30-year and five-year Senior Notes. Additionally, we issued $225 million of our common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions. In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million. The shelf registration statement will allow us to issue additional common units from time to time, which we intend to conduct under an equity distribution agreement with one or more financial institutions in the future. We have a Commercial Paper Program pursuant to which we had no amounts outstanding as of June 30, 2014. As of June 30, 2014, the unused capacity under the Amended and Restated Credit Agreement was $1,249 million, all of which was available for general working capital purposes, providing liquidity to continue to execute on our growth plans.

We raised our distribution for the quarter, resulting in an approximately 7% increase in our quarterly distribution rate over the rate declared for the second quarter of 2013. The distribution reflects our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

During 2014, our strategic objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio, our fee-based business which represents a significant portion of our estimated margins, plus our highly hedged commodity position, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $35 million and $45 million, and approved expenditures for expansion capital of between $500 million and $600 million, for the year ending December 31, 2014. Expansion capital expenditures include construction of Discovery's Keathley Canyon Connector, which is shown as investments in unconsolidated affiliates; construction of the Lucerne 2 plant; the Marysville NGL storage project and upgrade of our Chesapeake facility, among other projects. The board of directors may, at its discretion, approve additional growth capital during the year.

For an in-depth discussion of factors that may significantly affect our results, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations -- Factors That May Significantly Affect Our Results” included as Exhibit 99.2 in our Current Report on Form 8-K filed with the SEC on June 13, 2014.

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements include the historical results of our Lucerne 1 plant and a 46.67% 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.

Reconciliation of Non-GAAP Measures

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

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

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

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

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

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

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

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

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

Distributable Cash Flow — We define Distributable Cash Flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, net income attributable to noncontrolling interest net of depreciation and income tax, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities. Maintenance capital expenditures are cash expenditures made to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing Distributable Cash Flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices and interest rates. Distributable Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner.

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

Reconciliation of Non-GAAP Measures	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(Millions)			
Reconciliation of net income attributable to partners to gross margin:				
Net income attributable to partners	$ 29	$ 107	$ 108	$ 164
Interest expense	23	14	42	26
Income tax expense	1	—	4	1
Operating and maintenance expense	56	52	101	98
Depreciation and amortization expense	28	23	54	44
General and administrative expense	15	16	31	32
Other expense	—	—	1	4
Earnings from unconsolidated affiliates	(16)	(8)	(19)	(16)
Net income attributable to noncontrolling interests	—	4	10	7
Gross margin	$ 136	$ 208	$ 332	$ 360
Non-cash commodity derivative mark-to-market (a)	$ (30)	$ 58	$ (43)	$ 48
Reconciliation of segment net income attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net income attributable to partners	$ 40	$ 116	$ 130	$ 160
Operating and maintenance expense	49	44	87	83
Depreciation and amortization expense	26	21	50	40
Other expense	—	—	1	—
(Earnings) losses from unconsolidated affiliates	—	(1)	1	(1)
Net income attributable to noncontrolling interests	—	4	10	7
Segment gross margin	$ 115	$ 184	$ 279	$ 289
Non-cash commodity derivative mark-to-market (a)	$ (30)	$ 58	$ (42)	$ 49
NGL Logistics segment:				
Segment net income attributable to partners	$ 30	$ 20	$ 46	$ 42
Operating and maintenance expense	4	4	8	8
Depreciation and amortization expense	2	2	3	3
Earnings from unconsolidated affiliates	(16)	(7)	(20)	(15)
Segment gross margin	$ 20	$ 19	$ 37	$ 38
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners	$ (2)	$ 1	$ 9	$ 21
Operating and maintenance expense	3	4	6	7
Depreciation and amortization expense	—	—	1	1
Other expense	—	—	—	4
Segment gross margin	$ 1	$ 5	$ 16	$ 33
Non-cash commodity derivative mark-to-market (a)	$ —	$ —	$ (1)	$ (1)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
		(Millions)		
Reconciliation of net income attributable to partners to adjusted segment EBITDA:				
Natural Gas Services segment:				
Segment net income attributable to partners (a)	$ 40	$ 116	$ 130	$ 160
Non-cash commodity derivative mark-to-market	30	(58)	42	(49)
Depreciation and amortization expense	26	21	50	40
Noncontrolling interest on depreciation and income tax	—	(2)	(2)	(3)
Adjusted Segment EBITDA	$ 96	$ 77	$ 220	$ 148
NGL Logistics segment:				
Segment net income attributable to partners	$ 30	$ 20	$ 46	$ 42
Depreciation and amortization expense	2	2	3	3
Adjusted Segment EBITDA	$ 32	$ 22	$ 49	$ 45
Wholesale Propane Logistics segment:				
Segment net (loss) income attributable to partners (b)	$ (2)	$ 1	$ 9	$ 21
Non-cash commodity derivative mark-to-market	—	—	1	1
Depreciation and amortization expense	—	—	1	1
Adjusted Segment EBITDA	$ (2)	$ 1	$ 11	$ 23

(a) Includes no lower of cost or market adjustments for the three and six months ended June 30, 2014 and $2 million for the three and six months ended June 30, 2013.

(b) Includes no lower of cost or market adjustments for the three months ended June 30, 2014, $3 million of lower of cost or market adjustments for the six months ended June 30, 2014, and $1 million for the three and six months ended June 30, 2013.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 2 of the Notes to Consolidated Financial Statements included as Exhibits 99.2 and 99.3, respectively, in our Current Report on Form 8-K filed with the SEC on June 13, 2014. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and six months ended June 30, 2014 are the same as those described in our Current Report on Form 8-K filed on June 13, 2014. Certain information and note disclosures normally included in our annual financial statements prepared in accordance with GAAP have been condensed or omitted from the interim financial statements included in this Quarterly Report on Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission, although we believe that the disclosures made are adequate to make the information not misleading. The unaudited condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the audited consolidated financial statements and notes thereto in our Current Report on Form 8-K filed on June 13, 2014.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2014 and 2013. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2014 vs 2013		Variance Six Months 2014 vs. 2013	
	2014	2013 (a)	2014 (a)	2013 (a)(b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues (c):								
Natural Gas Services	$ 732	$ 720	$ 1,581	$ 1,295	$ 12	2 %	$ 286	22 %
NGL Logistics	20	19	37	38	1	5 %	(1)	(3)%
Wholesale Propane Logistics	60	53	275	208	7	13 %	67	32 %
Total operating revenues	812	792	1,893	1,541	20	3 %	352	23 %
Gross margin (d):								
Natural Gas Services	115	184	279	289	(69)	(38)%	(10)	(3)%
NGL Logistics	20	19	37	38	1	5 %	(1)	(3)%
Wholesale Propane Logistics	1	5	16	33	(4)	(80)%	(17)	(52)%
Total gross margin	136	208	332	360	(72)	(35)%	(28)	(8)%
Operating and maintenance expense	(56)	(52)	(101)	(98)	4	8 %	3	3 %
Depreciation and amortization expense	(28)	(23)	(54)	(44)	5	22 %	10	23 %
General and administrative expense	(15)	(16)	(31)	(32)	(1)	(6)%	(1)	(3)%
Other expense	—	—	(1)	(4)	—	— %	(3)	(75)%
Earnings from unconsolidated affiliates (e)	16	8	19	16	8	100 %	3	19 %
Interest expense	(23)	(14)	(42)	(26)	9	64 %	16	62 %
Income tax expense	(1)	—	(4)	(1)	1	100 %	3	300 %
Net income attributable to noncontrolling interests	—	(4)	(10)	(7)	(4)	(100)%	3	43 %
Net income attributable to partners	$ 29	$ 107	$ 108	$ 164	$ (78)	(73)%	$ (56)	(34)%
Other data:								
Non-cash commodity derivative mark-to-market	$ (30)	$ 58	$ (43)	$ 48	$ (88)	(152)%	$ (91)	(190)%
Natural gas throughput (MMcf/d) (f)	2,556	2,302	2,464	2,323	254	11 %	141	6 %
NGL gross production (Bbls/d) (f)	156,058	116,352	147,443	117,450	39,706	34 %	29,993	26 %
NGL pipelines throughput (Bbls/d) (f)	174,847	93,306	133,561	88,800	81,541	87 %	44,761	50 %
Propane sales volume (Bbls/d)	12,322	12,286	22,185	23,024	36	— %	(839)	(4)%

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.

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

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

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

(e) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery, our 33.33% ownership of each of the Sand Hills, Southern Hills and Front Range NGL pipelines, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of the Texas Express NGL pipeline. Earnings for Discovery, Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

(f) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of unconsolidated affiliates.

Three Months Ended June 30, 2014 vs. Three Months Ended June 30, 2013

Total Operating Revenues — Total operating revenues increased $20 million in 2014 compared to 2013 as a result of the following:

- $12 million increase for our Natural Gas Services segment primarily due to higher volumes and improved NGL recoveries at our Eagle Ford system, an increase in commodity prices, which impact both sales and purchases, and an increase in fee revenue; partially offset by a decrease as a result of commodity derivative activity, lower volumes related to our natural gas storage and pipeline assets and our other gathering and processing assets and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation; and

- $7 million increase for our Wholesale Propane Logistics segment primarily due to higher propane prices.

- Total operating revenues for our NGL Logistics segment remained relatively constant in 2014 compared to 2013.

Gross Margin — Gross margin decreased $72 million in 2014 compared to 2013, primarily as a result of the following:

- $69 million decrease for our Natural Gas Services segment, primarily related to a decrease as a result of commodity derivative activity, lower volumes and turnaround activity across certain assets and a change in the contract structure at our Lucerne 1 plant; partially offset by higher volumes and improved NGL recoveries at our Eagle Ford system, the operation of our O'Connor plant in our DJ Basin system and higher commodity prices before the impact of commodity derivative activity; and

- $4 million decrease for our Wholesale Propane Logistics segment primarily due to decreased unit margins.

- Gross margin for our NGL Logistics segment remained relatively constant in 2014 compared to 2013.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2014 compared to 2013 primarily as a result of the operation of the O'Connor and Goliad plants and turnaround activity across certain assets in our Natural Gas Services segment, partially offset by the expiration of our marine terminal lease in our Wholesale Propane Logistics segment.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2014 compared to 2013 primarily as a result of growth in our operations.

General and Administrative Expense — General and administrative expense remained relatively constant in 2014 compared to 2013.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of the March 2014 contribution of Sand Hills and Southern Hills in our NGL Logistics segment, partially offset by lower volumes and the timing of expenditures at Discovery in our Natural Gas Services segment.

Interest Expense — Interest expense increased in 2014 compared to 2013 as a result of higher outstanding debt balances associated with the growth in our operations.

Income Tax Expense — Income tax expense increased in 2014 compared to 2013 primarily due to growth in our business.

Net Income Attributable to Noncontrolling Interests — Net income attributable to noncontrolling interests decreased in 2014 compared to 2013 primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system.

Six Months Ended June 30, 2014 vs. Six Months Ended June 30, 2013

Total Operating Revenues — Total operating revenues increased $352 million in 2014 compared to 2013 as a result of the following:

- $286 million increase for our Natural Gas Services segment primarily due to an increase in commodity prices, which impact both sales and purchases, higher volumes and improved NGL recoveries at our Eagle Ford system, and an increase in fee revenue, partially offset by a decrease as a result of commodity derivative activity, a decrease as a result of commodity derivative activity and lower volumes related to our natural gas storage and pipeline assets and our other gathering and processing assets; and

- $67 million increase for our Wholesale Propane Logistics segment primarily due to higher propane prices, partially offset by lower volumes and a decrease as a result of commodity derivative activity.

These increases were partially offset by:

- $1 million decrease for our NGL Logistics segment primarily due to lower customer inventory and related fees at our NGL storage facility, partially offset by increased throughput on certain of our pipelines.

Gross Margin — Gross margin decreased $28 million in 2014 compared to 2013, primarily as a result of the following:

- $17 million decrease for our Wholesale Propane Logistics segment primarily due to decreased unit margins, a decrease in volumes due to the export of propane from our Chesapeake terminal in 2013 and a decrease as a result of commodity derivative activity;

- $10 million decrease for our Natural Gas Services segment, primarily related to a decrease as a result of commodity derivative activity, a change in the contract structure at our Lucerne 1 plant and lower volumes and turnaround activity across certain assets; partially offset by a favorable contractual producer settlement, the operation of our O'Connor plant in our DJ Basin system, higher volumes and improved NGL recoveries, higher unit margins on our storage assets and higher commodity prices before the impact of commodity derivative activity; and

- $1 million decrease for our NGL Logistics segment as a result of lower customer inventory and related fees at our NGL storage facility, partially offset by increased throughput on certain of our pipelines.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2014 compared to 2013primarily as a result of the operation of the O'Connor and Goliad plants and turnaround activity across certain assets in our Natural Gas Services segment, partially offset by the expiration of our marine terminal lease in our Wholesale Propane Logistics segment.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2014 compared to 2013 primarily as a result of growth in our operations.

General and Administrative Expense — General and administrative expense remained relatively constant in 2014 compared to 2013.

Other Expense — Other expense in 2014 and 2013 represents a write off of construction work in progress due to discontinued projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of the March 2014 contribution of Sand Hills and Southern Hills in our NGL Logistics segment, partially offset by lower volumes due to maintenance and unfavorable location pricing at our Mont Belvieu fractionators in our NGL Logistics segment, and lower volumes and the timing of expenditures at Discovery in our Natural Gas Services segment.

Interest Expense — Interest expense increased in 2014 compared to 2013 as a result of higher outstanding debt balances associated with the growth in our operations.

Income Tax Expense — Income tax expense increased in 2014 compared to 2013 primarily due to growth in our business.

Net Income Attributable to Noncontrolling Interests — Net income attributable to noncontrolling interests increased in 2014 compared to 2013 primarily as a result of favorable cumulative producer settlements, higher volumes and improved NGL recoveries at our Eagle Ford system, partially offset by the contribution of the remaining 20% interest in the Eagle Ford system in March 2014.

Results of Operations — Natural Gas Services Segment

The results of operations for our Natural Gas Services segment are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2014 vs. 2013		Variance Six Months 2014 vs. 2013	
	2014	2013 (a)	2014 (a)	2013 (a)(b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 694	$ 607	$ 1,492	$ 1,138	$ 87	14 %	$ 354	31 %
Transportation, processing and other	60	42	126	87	18	43 %	39	45 %
Losses from commodity derivative activity	(22)	71	(37)	70	(93)	(131)%	(107)	153 %
Total operating revenues	732	720	1,581	1,295	12	2 %	286	22 %
Purchases of natural gas and NGLs	(617)	(536)	(1,302)	(1,006)	81	15 %	296	29 %
Segment gross margin (c)	115	184	279	289	(69)	(38)%	(10)	(3)%
Operating and maintenance expense	(49)	(44)	(87)	(83)	5	11 %	4	5 %
Depreciation and amortization expense	(26)	(21)	(50)	(40)	5	24 %	10	25 %
Other expense	—	—	(1)	—	—	— %	1	100 %
Earnings (losses) from unconsolidated affiliates (d)	—	1	(1)	1	(1)	(100)%	(2)	(200)%
Segment net income	40	120	140	167	(80)	(67)%	(27)	(16)%
Segment net income attributable to noncontrolling interests	—	(4)	(10)	(7)	(4)	(100)%	3	43 %
Segment net income attributable to partners	$ 40	$ 116	$ 130	$ 160	$ (76)	(66)%	$ (30)	(19)%
Other data:								
Non-cash commodity derivative mark-to-market	$ (30)	$ 58	$ (42)	$ 49	$ (88)	(152)%	$ (91)	(186)%
Natural gas throughput (MMcf/d) (e)	2,556	2,302	2,464	2,323	254	11 %	141	6 %
NGL gross production (Bbls/d) (e)	156,058	116,352	147,443	117,450	39,706	34 %	29,993	26 %

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.
(b) Includes the results of an 80% interest in the Eagle Ford system, retrospectively adjusted. We acquired a 46.67% interest on March 28, 2013 and a 33.33% interest on November 2, 2012.
(c) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read “Reconciliation of Non-GAAP Measures” above.
(d) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery. Earnings for Discovery include the amortization of the net difference between the carrying amount of our investment and the underlying equity of the entity.
(e) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of unconsolidated affiliates.

Three Months Ended June 30, 2014 vs. Three Months Ended June 30, 2013

Total Operating Revenues — Total operating revenues increased $12 million in 2014 compared to 2013, primarily as a result of the following:

- $66 million increase attributable to increased commodity prices, which impact both sales and purchases;
- $48 million increase primarily attributable to higher volumes and improved NGL recoveries at our Eagle Ford system, in part due to the operation of our Goliad plant. This increase was partially offset by lower volumes across our other gathering and processing assets;
- $18 million increase in fee revenue primarily attributable to the operation of our O'Connor plant in our DJ Basin system and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation; and
- $6 million increase attributable to increased prices related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems.

These increases were partially offset by:

- $93 million decrease as a result of commodity derivative activity. This includes a decrease in realized cash settlement gains in 2014 compared to 2013 of $5 million, and unrealized commodity derivative losses in 2014 compared to unrealized commodity derivative gains in 2013 for a net decrease of $88 million due to movements in forward prices of commodities;
- $17 million decrease attributable to a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation; and
- $16 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $81 million in 2014 compared to 2013 primarily as a result of higher commodity prices and increased volumes at our Eagle Ford system. These increases were partially offset by decreased volumes at our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems, lower volumes across certain gathering and processing assets and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation.

Segment Gross Margin — Segment gross margin decreased $69 million in 2014 compared to 2013, primarily as a result of the following:

- $93 million decrease as a result of commodity derivative activity as discussed above.

This decrease was partially offset by:

- $21 million increase attributable to higher volumes and improved NGL recoveries at our Eagle Ford system and the operation of our O'Connor plant in our DJ Basin system; partially offset by lower volumes and turnaround activity across certain assets and a change in the contract structure at our Lucerne 1 plant; and
- $3 million increase as a result of higher commodity prices before the impact of commodity derivative activity.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2014 compared to 2013 primarily as a result of the operation of the O'Connor and Goliad plants and turnaround activity across certain assets.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2014 compared to 2013 primarily as a result of growth in our operations.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2014 compared to 2013 primarily as a result of lower volumes, partially offset by timing of expenditures, at Discovery. Commodity derivative activity associated with our exposure on our unconsolidated affiliates is included in segment gross margin.

Segment Net Income Attributable to Noncontrolling Interests - Segment net income attributable to noncontrolling interests decreased in 2014 compared to 2013, primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system.

Natural Gas Throughput - Natural gas throughput increased in 2014 compared to 2013 primarily as a result of higher volumes at our Eagle Ford system and the operation of our Eagle and O'Connor plants; partially offset by lower volumes across certain assets, primarily our Southeast Texas system and Discovery.

NGL Gross Production - NGL production increased in 2014 compared to 2013 primarily as a result of higher volumes at our Eagle Ford system and the operation of our Eagle and O'Connor plants; partially offset by lower volumes across certain assets, primarily our Southeast Texas system.

Six Months Ended June 30, 2014 vs. Six Months Ended June 30, 2013

Total Operating Revenues — Total operating revenues increased $286 million in 2014 compared to 2013, primarily as a result of the following:

- $192 million increase attributable to increased commodity prices, which impact both sales and purchases;
- $146 million increase primarily attributable to higher volumes and improved NGL recoveries at our Eagle Ford system, in part due to the operation of our Eagle and Goliad plants. This increase was partially offset by lower volumes across our other gathering and processing assets**;**
- $61 million increase attributable to increased prices related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems; and
- $39 million increase in fee revenue primarily attributable to higher volumes at our Eagle Ford system, as well as the operation of our O'Connor plant in our DJ Basin system and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation.

These increases were partially offset by:

- $107 million decrease as a result of commodity derivative activity. This includes a decrease in realized cash settlement gains in 2014 compared to 2013 of $16 million, and unrealized commodity derivative losses in 2014 compared to unrealized commodity derivative gains in 2013 for a net decrease of $91 million due to movements in forward prices of commodities;
- $28 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems; and
- $17 million decrease attributable to a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $296 million in 2014 compared to 2013 primarily as a result of higher commodity prices and increased volumes at our Eagle Ford system. These increases were partially offset by decreased volumes at our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems, lower volumes across certain gathering and processing assets and a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation.

Segment Gross Margin — Segment gross margin decreased $10 million in 2014 compared to 2013, primarily as a result of the following:

- $107 million decrease as a result of commodity derivative activity as discussed above.

This decrease was partially offset by:

- $66 million increase attributable to a favorable contractual producer settlement, the operation of our O'Connor plant in our DJ Basin system, and higher volumes and improved NGL recoveries at our Eagle Ford system; partially offset by lower volumes and turnaround activity across certain assets and a change in the contract structure at our Lucerne 1 plant;
- $20 million increase attributable to higher unit margins on our storage assets; and
- $11 million increase as a result of higher commodity prices before the impact of commodity derivative activity.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2014 compared to 2013 primarily as a result of the operation of the O'Connor and Goliad plants and turnaround activity across certain assets.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2014 compared to 2013 primarily as a result of growth in our operations.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2014 compared to 2013 primarily as a result of lower volumes, partially offset by timing of expenditures, at Discovery. Commodity derivative activity associated with our exposure on our unconsolidated affiliates is included in segment gross margin.

Segment Net Income Attributable to Noncontrolling Interests - Segment net income attributable to noncontrolling interests increased in 2014 compared to 2013, primarily as a result of favorable cumulative producer settlements, higher volumes and improved NGL recoveries at our Eagle Ford system, partially offset by the contribution of the remaining 20% interest in the Eagle Ford system in March 2014.

Natural Gas Throughput - Natural gas throughput increased in 2014 compared to 2013 primarily as a result of higher volumes at our Eagle Ford system and the operation of our Eagle and O'Connor plants; partially offset by lower volumes across certain assets, primarily our Southeast Texas system and Discovery.

NGL Gross Production - NGL production increased in 2014 compared to 2013 primarily as a result of higher volumes at our Eagle Ford system and the operation of our Eagle and O'Connor plants; partially offset by lower volumes across certain assets.

Results of Operations — NGL Logistics Segment

The results of operations for our NGL Logistics segment are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2014 vs. 2013		Variance Six Months 2014 vs. 2013	
	2014	2013	2014	2013	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues:								
Transportation, processing and other	20	19	37	38	1	5%	(1)	(3)%
Segment gross margin (a)	20	19	37	38	1	5%	(1)	(3)%
Operating and maintenance expense	(4)	(4)	(8)	(8)	—	—%	—	— %
Depreciation and amortization expense	(2)	(2)	(3)	(3)	—	—%	—	— %
Earnings from unconsolidated affiliates (b)	16	7	20	15	9	129%	5	33 %
Segment net income attributable to partners	$ 30	$ 20	$ 46	$ 42	$ 10	50%	$ 4	10 %
Other data:								
NGL pipelines throughput (Bbls/d) (c)	174,847	93,306	133,561	88,800	81,541	87%	44,761	50 %

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

(b) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 33.33% ownership in each of the Sand Hills and Southern Hills pipelines, which were contributed to us in March 2014, our 33.33% ownership of the Front Range pipeline, which commenced operations in February 2014, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of the Texas Express pipeline, which commenced operations in October 2013. Earnings for Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of our investments and the underlying equity of the entities.

(c) Includes our share, based on our ownership percentage, of the throughput volumes of unconsolidated affiliates.

Three Months Ended June 30, 2014 vs. Three Months Ended June 30, 2013

Total Operating Revenues and Segment Gross Margin — Total operating revenues remained relatively constant in 2014 compared to 2013.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2014 compared to 2013.

Depreciation and Amortization Expense — Depreciation and amortization remained constant in 2014 compared to 2013.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of the contribution of Sand Hills and Southern Hills in March 2014.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2014 compared to 2013 as a result of volume growth on certain of our pipelines, including Sand Hills and Southern Hills which were contributed to us in March 2014, Front Range which commenced operations in February 2014, and Texas Express which commenced operations in October 2013.

Six Months Ended June 30, 2014 vs. Six Months Ended June 30, 2013

Total Operating Revenues and Segment Gross Margin — Total operating revenues decreased in 2014 compared to 2013 as result of lower customer inventory and related fees at our NGL storage facility; partially offset by increased throughput on certain of our pipelines.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2014 compared to 2013.

Depreciation and Amortization Expense — Depreciation and amortization remained constant in 2014 compared to 2013.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2014 compared to 2013 primarily as a result of the contribution of Sand Hills and Southern Hills in March 2014, partially offset by lower volumes due to maintenance and unfavorable location pricing at our Mont Belvieu fractionators.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2014 compared to 2013 as a result of volume growth on certain of our pipelines, including Sand Hills and Southern Hills which were contributed to us in March 2014, Front Range which commenced operations in February 2014, and Texas Express which commenced operations in October 2013.

Results of Operations — Wholesale Propane Logistics Segment

The results of operations for our Wholesale Propane Logistics segment are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2014 vs 2013		Variance Six Months 2014 vs. 2013	
	2014	2013	2014	2013	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues:								
Sales of propane	$ 60	$ 53	$ 275	$ 207	$ 7	13 %	$ 68	33 %
Gains from commodity derivative activity	—	—	—	1	—	— %	(1)	(100)%
Total operating revenues	60	53	275	208	7	13 %	67	32 %
Purchases of propane	(59)	(48)	(259)	(175)	11	23 %	84	48 %
Segment gross margin (a)	1	5	16	33	(4)	(80)%	(17)	(52)%
Operating and maintenance expense	(3)	(4)	(6)	(7)	(1)	(25)%	(1)	(14)%
Depreciation and amortization expense	—	—	(1)	(1)	—	— %	—	— %
Other expense	—	—	—	(4)	—	— %	(4)	(100)%
Segment net income attributable to partners	$ (2)	$ 1	$ 9	$ 21	$ (3)	(300)%	$ (12)	(57)%
Other data:								
Non-cash commodity derivative mark-to-market	$ —	$ —	$ (1)	$ (1)	$ —	— %	$ —	— %
Propane sales volume (Bbls/d)	12,322	12,286	22,185	23,024	36	— %	(839)	(4)%

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

Three Months Ended June 30, 2014 vs. Three Months Ended June 30, 2013

Total Operating Revenues — Total operating revenues increased by $7 million in 2014 compared to 2013, primarily as a result of higher propane prices.

Purchases of Propane — Purchases of propane increased in 2014 compared to 2013 primarily due to higher propane prices, which impact both sales and purchases.

Segment Gross Margin — Segment gross margin decreased in 2014 compared to 2013 primarily due to decreased unit margins.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2014 compared to 2013 primarily as a result of the expiration of our marine terminal lease in April 2014.

Depreciation and Amortization Expense — Depreciation and amortization expense remained constant in 2014 compared to 2013.

Propane Sales Volume — Propane sales volumes remained relatively constant in 2014 compared to 2013.

Six Months Ended June 30, 2014 vs. Six Months Ended June 30, 2013

Total Operating Revenues — Total operating revenues increased by $67 million in 2014 compared to 2013, primarily as a result of the following:

- $75 million increase attributable to higher propane prices.

This increase was partially offset by:

- $7 million decrease attributable to decreased volumes. In 2013, we had an increase in volumes due to the export of propane from our Chesapeake terminal; and
- $1 million decrease as a result of commodity derivative activity. This includes a decrease in realized cash settlement gains in 2014 compared to 2013 of $1 million.

Purchases of Propane — Purchases of propane increased in 2014 compared to 2013 primarily due to higher propane prices, which impact both sales and purchases, partially offset by lower volumes.

Segment Gross Margin — Segment gross margin decreased in 2014 compared to 2013 primarily due to decreased unit margins, a decrease in volumes due to the export of propane from our Chesapeake terminal in 2013, and a $1 million decrease related to commodity derivative activities as discussed above.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2014 compared to 2013 primarily as a result of the expiration of our marine terminal lease in April 2014.

Depreciation and Amortization Expense — Depreciation and amortization expense remained constant in 2014 compared to 2013.

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

Propane Sales Volume — Propane sales volumes decreased in 2014 compared to 2013. In 2013, we had an increase in volumes due to the export of propane from our Chesapeake terminal.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our revolving Amended and Restated Credit Agreement;
- issuance of commercial paper under our Commercial Paper Program;
- borrowings under term loans;
- issuance of additional common units, including issuances we may make to DCP Midstream, LLC;
- debt offerings; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- quarterly distributions to our unitholders and general partner;
- growth capital expenditures;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions, including transactions with DCP Midstream, LLC; and
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements, and letters of credit we have posted.

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

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

Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our ongoing business, although deterioration in our operating environment could limit our borrowing capacity, impact our credit ratings, raise our financing costs, as well as impact our compliance with our financial covenant requirements under our Amended and Restated Credit Agreement.

In May 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement, which replaced our previous $1 billion Credit Agreement scheduled to mature on November 10, 2016. Our Commercial Paper Program serves as an alternative source of funding, and does not increase our current overall borrowing capacity. Amounts available under the Commercial Paper Program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of notes outstanding, combined with the amount outstanding under our Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. As of July 31, 2014, we had no commercial paper or credit facility borrowings outstanding and had approximately $1.25 billion of unused capacity under the Amended and Restated Credit Agreement.

In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million, and $392 million, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the March 2014 Transactions. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, unless redeemed prior to maturity.

In March 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 acquisition of an additional 46.67% interest in the Eagle Ford system.

In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement will allow us to issue additional common units from time to time, which we intend to conduct under an equity distribution agreement with one or more financial institutions in the future. As of June 30, 2014, we have issued no securities under this registration statement.

In March 2014, we issued 14,375,000 common units to the public at $48.90 per unit. We received proceeds of $677 million, net of offering costs.

In March 2014, we issued 4,497,158 common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions.

In November 2013, we entered into an equity distribution agreement, or the 2013 equity distribution agreement, with a group of financial institutions as sales agents. The agreement provides for the offer and sale from time to time, through our sales agents, of common units having an aggregate offering amount of up to $300 million. During the six months ended June 30, 2014, we issued 2,011,000 common units pursuant to the 2013 equity distribution agreement and received proceeds of $110 million, which is net of commissions and offering costs of $1 million. The proceeds were used to finance growth opportunities and for general partnership purposes. As of June 30, 2014, approximately $101 million aggregate offering price of our common units remain available for sale pursuant to the 2013 equity distribution agreement.

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

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

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a significant portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2017 with fixed price commodity swaps. For additional information regarding our derivative activities, please read Part 1, Item 3 - Quantitative and Qualitative Disclosures about Market Risk contained herein and "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" in our 2013 Form 10-K.

The counterparties to certain of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. The counterparty to our remaining commodity swaps contracts is DCP Midstream, LLC.

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

We had working capital of $107 million as of June 30, 2014, compared to a working capital deficit of $220 million as of December 31, 2013. Included in these working capital amounts are net derivative working capital of $61 million and $51 million as of June 30, 2014 and December 31, 2013, respectively. The change in working capital is primarily attributable to the repayment of our commercial paper borrowings, as well as the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of June 30, 2014, we had $57 million in cash and cash equivalents. Of this balance, $1 million was held by consolidated subsidiaries we do not wholly own. Other than the cash held by these subsidiaries, this cash balance was available for general partnership purposes.

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

	Six Months Ended June 30,	
	2014	2013
	(Millions)	
Net cash provided by operating activities	$ 300	$ 281
Net cash used in investing activities	$ (998)	$ (768)
Net cash provided by financing activities	$ 743	$ 494

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

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

We received $6 million for our net hedge cash settlements for the six months ended June 30, 2014 and received $23 million for our net hedge cash settlements for the six months ended June 30, 2013, of which less than $1 million was associated with rebalancing our portfolio.

We received cash distributions from unconsolidated affiliates of $40 million and $22 million during the six months ended June 30, 2014 and 2013, respectively. Distributions exceeded earnings by $21 million for the six months ended June 30, 2014.

Net Cash Used in Investing Activities — Net cash used in investing activities during the six months ended June 30, 2014 was comprised of: (1) the acquisition of unconsolidated affiliates of $669 million related to the contribution of 33.33% interests in each of the Sand Hills and Southern Hills pipelines; (2) capital expenditures of $151 million (our portion of which was $146 million and the noncontrolling interests portion was $5 million) consisting of construction of the Goliad plant, expansion of the O'Connor plant, upgrade of our Chesapeake facility and other projects; (3) acquisitions of $102 million related to our acquisition of the Lucerne 1 and Lucerne 2 plants; and (4) investments in unconsolidated affiliates of $93 million consisting of

$48 million to Discovery, $34 million to Front Range, $5 million to Texas Express, $4 million to Southern Hills and $2 million to Sand Hills; partially offset by proceeds from sales of assets of $17 million.

Net cash used in investing activities during the six months ended June 30, 2013 was comprised of: (1) acquisition expenditures of $486 million related to our acquisition of the additional 46.67% interest in the Eagle Ford system; (2) capital expenditures of $195 million (our portion of which was $171 million and the reimbursable projects portion was $24 million); and (3) investments in unconsolidated affiliates of $87 million.

Net Cash Provided by Financing Activities — Net cash provided by financing activities during the six months ended June 30, 2014 was comprised of: (1) proceeds from the issuance of common units, net of offering costs, of $787 million; (2) proceeds from long-term debt of $719 million; and (3) contributions from noncontrolling interests of $3 million; partially offset by (4) net commercial paper activity of $335 million; (5) purchase of additional interest in a subsidiary of $198 million; (6) distributions to our limited partners and general partner of $192 million; (7) excess purchase price over acquired interests of $15 million; (8) distributions to noncontrolling interests of $11 million; (9) payment of deferred financing costs of $9 million; and (10) net change in advances to predecessor from DCP Midstream, LLC of $6 million.

As of June 30, 2014, we had unused capacity under the Amended and Restated Credit Agreement of $1,249 million, all of which was available for general working capital purposes.

Net cash provided by financing activities during the six months ended June 30, 2013 was comprised of: (1) proceeds from long-term debt of $1,079 million, offset by payments of $960 million, for net borrowing of long-term debt of $119 million; (2) proceeds from the issuance of common units net of offering costs of $563 million; (3) contributions from noncontrolling interest of $31 million (4) net change in advances to predecessor from DCP Midstream, LLC of $21 million; and (5) contributions from DCP Midstream, LLC of $1 million; partially offset by (6) distributions to our limited partners and general partner of $123 million; (7) excess purchase price over acquired interests and commodity hedges of $101 million; (8) distributions to noncontrolling interests of $10 million; (9) payments of deferred financing costs of $4 million; and (10) distributions to DCP Midstream, LLC of $3 million relating to capital expenditures for reimbursable projects.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 11. "Partnership Equity and Distributions" in the Notes to Condensed Consolidated Financial Statements in Item 1. “Financial Statements”

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

- maintenance capital expenditures, which are cash expenditures to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets; and

- expansion capital expenditures, which are cash expenditures to increase our cash flows, operating or earnings capacity. Expansion capital expenditures include acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines and well connects, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets).

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $35 million and $45 million, and approved expenditures for expansion capital of between $500 million and $600 million, for the year ending December 31, 2014. Expansion capital expenditures include construction of Discovery’s Keathley Canyon Connector, which is shown as investments in unconsolidated affiliates; construction of the Lucerne 2 plant; the Marysville NGL storage project and upgrade of our Chesapeake facility, among other projects. The board of directors may, at its discretion, approve additional growth capital during the year.

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

	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 17	$ 129	$ 146	$ 10	$ 161	$ 171
Noncontrolling interest portion and reimbursable projects (a)	1	4	5	1	23	24
Total	$ 18	$ 133	$ 151	$ 11	$ 184	$ 195

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

In addition, we invested cash in unconsolidated affiliates of $93 million and $87 million, net of returns, during the six months ended June 30, 2014 and 2013, respectively, to fund our share of capital expansion projects.

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

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

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $192 million and $123 million during the six months ended June 30, 2014 and 2013, respectively. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Description of the Amended and Restated Credit Agreement — On May 1, 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement, which replaced our previous $1 billion Credit Agreement scheduled to mature on November 10, 2016.

As of June 30, 2014, there was no outstanding balance on the revolving credit facility under the Amended and Restated Credit Agreement and we had unused revolver capacity of $1,249 million, which is net of letters of credit.

Our obligations under the revolving credit facility are unsecured. The unused portion of the revolving credit facility may be used for letters of credit up to a maximum of $500 million of outstanding letters of credit. At June 30, 2014 and December 31, 2013, we had $1 million outstanding letters of credit issued under the Amended and Restated Credit Agreement. Amounts undrawn under the revolving credit facility are available to repay amounts borrowed under our Commercial Paper Program, if necessary.

We may prepay all loans at any time without penalty, subject to the reimbursement of lender breakage costs in the case of prepayment of London Interbank Offered Rate, or LIBOR, borrowings. Indebtedness under the Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.275% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.275% based on our current credit rating. The revolving credit facility incurs an annual facility fee of 0.225% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion revolving credit facility.

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

Description of Commercial Paper Program – We have a Commercial Paper Program under which we may issue unsecured commercial paper notes, or the Notes. The Commercial Paper Program serves as an alternative source of funding and does not increase our current overall borrowing capacity. Amounts available under the Commercial Paper Program may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of Notes outstanding, combined with the amount outstanding under our Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. Amounts undrawn under our Amended and Restated Credit Agreement are available to repay the Notes, if necessary. The maturities of the Notes will vary, but may not exceed 397 days from the date of issue. The Notes will be sold under customary terms in the commercial paper market and may be issued at a discount from par, or, alternatively, may be sold at par and bear varying interest rates on a fixed or floating basis. The proceeds of the issuances of the Notes are expected to be used for capital expenditures and other general partnership purposes. As of June 30, 2014, we had no commercial paper outstanding.

Description of Debt Securities – In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million and $392 million, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the contribution and acquisition of (i) a 33.33% interest in each of the Sand Hills and Southern Hills pipeline entities; (ii) the remaining 20% interest in the Eagle Ford system; (iii) the Lucerne 1 plant; and (iv) the Lucerne 2 plant. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, unless redeemed prior to maturity.

In March 2013, we issued $500 million of 3.875% 10-year Senior Notes due March 15, 2023. We received proceeds of $490 million, net of underwriters' fees, related expenses and unamortized discounts totaling $10 million, which we used to fund the cash portion of the purchase price for the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes is 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 condensed consolidated balance sheets and will be amortized over the term of the notes.

The series of notes are senior unsecured obligations, ranking equally in right of payment with our existing unsecured indebtedness, including indebtedness under our Amended and Restated 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.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of June 30, 2014, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(Millions)				
Debt (a)	$ 3,411	$ 90	$ 415	$ 967	$ 1,939
Operating lease obligations (b)	90	17	26	18	29
Purchase obligations (c)	329	325	1	—	3
Other long-term liabilities (d)	27	—	1	—	26
Total	$ 3,857	$ 432	$ 443	$ 985	$ 1,997

(a) Includes interest payments on debt securities that have been issued. These interest payments are $90 million, $165 million, $142 million, and $689 million for less than one year, one to three years, three to five years, and thereafter, respectively.

(b) Our operating lease obligations are contractual obligations and include railcar leases, which provide supply and storage infrastructure for our Wholesale Propane Logistics business, and natural gas storage in our Northern Louisiana system and a firm transportation commitment within our Natural Gas Services business. The natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the futures market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index, the amount is based on the forward market prices as of June 30, 2014. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the condensed consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the condensed consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(d) Other long-term liabilities include $26 million of asset retirement obligations and $1 million of environmental reserves recognized in the June 30, 2014 condensed consolidated balance sheet. In addition, $12 million of deferred state income taxes were excluded as cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year.

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

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

For an in-depth discussion of our market risks, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" in our 2013 Form 10-K.

The following tables set forth additional information about our fixed price swaps used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations, as of July 31, 2014:

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Reference Price	Price Range
July 2014 — December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$5.06/MMBtu
July 2014 — December 2014	Natural Gas	(21,422) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	$4.50/MMBtu
January 2015 — December 2015	Natural Gas	(24,738) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(16,163) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (e)	$4.50/MMBtu
July 2014 — December 2014	Natural Gas	(6,766) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
January 2015 — December 2015	Natural Gas	(8,677) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(4,041) MMBtu/d	IFERC Monthly Index Price for Henry Hub (f)	$4.50/MMBtu
July 2014 — December 2014	Natural Gas	(2,500) MMBtu/d	NYMEX Final Settlement Price (g)	$4.26/MMBtu
January 2016 — December 2016	Natural Gas	(5,000) MMBtu/d	NYMEX Final Settlement Price (g)	$4.18/MMBtu
January 2017 — December 2017	Natural Gas	(17,500) MMBtu/d	NYMEX Final Settlement Price (g)	$4.17 - $4.27/MMBtu
July 2014 — December 2014	NGL's	(16,554) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64 - $2.60/Gal
January 2015 — March 2015	NGL's	(16,893) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64 - $2.60/Gal
April 2015 — December 2015	NGL's	(15,168) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64 - $1.89/Gal
January 2016 — March 2016	NGL's	(8,937) Bbls/d	Mt.Belvieu Non-TET (d)	$0.64 - $1.89/Gal
July 2014 — December 2014	Crude Oil	(1,893) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$74.90 - $96.08/Bbl
January 2015 — December 2015	Crude Oil	(2,043) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$87.60 - $100.04/Bbl
January 2016 — March 2016	Crude Oil	(1,642) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$85.15 - $101.30/Bbl
April 2016 — December 2016	Crude Oil	(1,500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$85.15 - $101.30/Bbl
July 2014 — December 2014	Natural Gas	5,000 MMBtu/d	NYMEX Final Settlement Price (g)	$3.93 - $4.02/MMBtu
January 2015 — December 2015	Natural Gas	7,500 MMBtu/d	NYMEX Final Settlement Price (g)	$4.15 - $4.22/MMBtu
July 2014 — December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	$4.93/MMBtu

(a) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.

(b) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.
(c) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(d) The average monthly OPIS price for Mt. Belvieu Non-TET.
(e) The Inside FERC monthly published index price for Houston Ship Channel.
(f) The inside FERC monthly published index price for Henry Hub.
(g) NYMEX final settlement price for natural gas futures contracts (NG).

Our sensitivities for 2014 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2014, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize direct product crude oil, natural gas and NGL derivatives to mitigate a significant portion of our condensate, natural gas and NGL commodity price exposure. These sensitivities are associated with our unhedged condensate, natural gas and NGL volumes.

Commodity Sensitivities Excluding Non-Cash Mark-To Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners
			(Millions)
Natural gas prices	$ 0.10	MMBtu	$ —
Crude oil prices	$ 1.00	Barrel	$ —
NGL prices	$ 0.01	Gallon	$ 0.7

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

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

We estimate the following non-cash sensitivities for 2014 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners)
			(Millions)
Natural gas prices	$ 0.10	MMBtu	$ 2
Crude oil prices	$ 1.00	Barrel	$ 2
NGL prices	$ 0.01	Gallon	$ 4

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

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2017.

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

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

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

The following tables set forth additional information about our derivative instruments used to mitigate a portion of our natural gas price risk associated with our Southeast Texas storage operations, as of June 30, 2014:

Inventory

Period ended	Commodity	Notional Volume - Long Positions	Fair Value (millions)	Weighted Average Price
June 30, 2014	Natural Gas	2,328,893 MMBtu	$ 11	$4.54/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Fair Value (millions)	Price Range
July 2014-December 2015	Natural Gas	(42,732,500) MMBtu	$ (2)	$3.66-$4.80/MMBtu
July 2014-December 2015	Natural Gas	38,397,500 MMBtu	$ 5	$3.66-$4.74/MMBtu

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

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission, or the Commission, under the Securities Exchange Act of 1934, as amended, or the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner's principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of June 30, 2014, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of June 30, 2014, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2014 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) issued an updated version of its Internal Control - Integrated Framework (2013 Framework). Originally issued in 1992 (1992 Framework), the framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. The 1992 Framework remains available during the transition period, which extends to December 15, 2014, after which time COSO will consider it as superseded by the 2013 Framework. As of June 30, 2014, we continue to utilize the 1992 Framework during the transition to the 2013 Framework by the end of 2014.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

The information required for this item is provided in "Commitments and Contingent Liabilities," included in Note 16 in Exhibit 99.3 in our Current Report on Form 8-K filed with the SEC on June 13, 2014 and Note 13 in Item 1 of this Quarterly Report on Form 10-Q.

Item 1A. *Risk Factors*

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, "Item 1A. Risk Factors" in our 2013 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2013 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our consolidated results of operations, financial condition and cash flows.

Item 6. Exhibits

Exhibit Number		Description
3.1	*	Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005, as amended by Amendment No. 1 dated January 20, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.2	*	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated February 14, 2013 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
3.3	*	Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated November 6, 2013 (attached as Exhibit 3.3 to DCP Midstream Partners, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on November 6, 2013).
3.4	*	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP dated December 7, 2005 (attached as Exhibit 3.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
3.5	*	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated November 1, 2006 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.6	*	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008).
3.7	*	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 1, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
10.1	*	Amended and Restated Credit Agreement, dated May 1, 2014, among DCP Midstream Operating, LP, DCP Midstream Partners, LP, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (attached as Exhibit 10.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 7, 2014).
12.1		Computation of Ratio of Earnings to Fixed Charges.
31.1		Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2		Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1		Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2		Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101		Financial statements of DCP Midstream Partners, LP from the Quarterly Report on Form 10-Q for the period ended June 30, 2014, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity, and (vi) the Notes to the Condensed Consolidated Financial Statements.

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

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on August 6, 2014.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

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

By: /s/ Sean P. O'Brien
Name: Sean P. O'Brien
Title: Group Vice President and Chief Financial Officer
(Principal Financial Officer)

Table of Contents

EXHIBIT INDEX

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

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

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

	DCP Midstream Partners, LP				
	Six Months Ended June 30,	Year Ended December 31,			
	2014 (a)	2013 (a)	2012 (a)	2011 (a)	2010 (a)
	(Millions)				
Earnings from continuing operations before fixed charges:					
Pretax income from continuing operations before earnings from unconsolidated affiliates	$ 93	$ 175	$ 191	$ 169	$ 104
Fixed charges	45	68	50	36	30
Amortization of capitalized interest	—	1	—	—	—
Distributed earnings from unconsolidated affiliates	19	33	24	23	23
Less:					
Capitalized interest	(3)	(15)	(7)	(2)	—
Earnings from continuing operations before fixed charges	$ 154	$ 262	$ 258	$ 226	$ 157
Fixed charges:					
Interest expense, net of capitalized interest	39	48	39	33	29
Capitalized interest	3	15	7	2	—
Estimate of interest within rental expense	—	1	1	—	1
Amortization of deferred loan costs	3	4	3	1	—
Total fixed charges	$ 45	$ 68	$ 50	$ 36	$ 30
Ratio of earnings to fixed charges	3.42	3.85	5.16	6.28	5.23

(a) The financial information for the six months ended June 30, 2014 and the years ended December 31, 2013, 2012, 2011 and 2010 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

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

Exhibit 31.1

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

I, Wouter T. van Kempen, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and six months ended June 30, 2014;

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2014

/s/ Wouter T. van Kempen

Wouter T. van Kempen
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

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

I, Sean P. O'Brien, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and six months ended June 30, 2014;

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2014

/s/ Sean P. O'Brien

Sean P. O'Brien
Group Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

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

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

(a) the quarterly report on Form 10-Q of the Partnership for the three and six months ended June 30, 2014, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Wouter T. van Kempen

Wouter T. van Kempen
Chief Executive Officer
(Principal Executive Officer)
August 6, 2014

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

Exhibit 32.2

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

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

(a) the quarterly report on Form 10-Q of the Partnership for the three and six months ended June 30, 2014, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Sean P. O'Brien

Sean P. O'Brien
Group Vice President and Chief Financial Officer
(Principal Financial Officer)
August 6, 2014

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