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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2017
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, 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) 595-3331

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒		Accelerated filer	☐	Emerging growth company	☐
Non-accelerated filer	☐	(Do not check if a smaller reporting company)	Smaller reporting company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a)
of the Exchange Act. ☐

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

As of May 5, 2017, there were 143,302,328 common units representing limited partner interests outstanding.

DCP MIDSTREAM, LP
FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2017

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GLOSSARY OF TERMS

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

Bbl	barrel
Bbls/d	barrels per day
Bcf	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, but not limited to, 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, 2016, 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 commodity prices through derivative financial instruments, and the potential impact of price, and of producers' access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- the demand for crude oil, residue gas and NGL products;
- the level and success of drilling and quality of production volumes around our assets and our ability to connect supplies to our gathering and processing systems, as well as our residue gas and NGL infrastructure;
- volatility in the price of our common units;
- general economic, market and business conditions;
- our ability to continue the safe and reliable operation of our assets;
- 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;
- 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 credit agreement and the indentures governing our notes, as well as our ability to maintain our credit ratings;
- the creditworthiness of our customers and the counterparties to our transactions;
- the amount of collateral we may be required to post from time to time in our transactions;
- industry changes, including the impact of bankruptcies, consolidations, alternative energy sources, technological advances and changes in competition;
- our ability to grow through organic growth projects, or acquisitions, and the successful integration and future performance of such assets;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- new, additions to, and changes in, laws and regulations, particularly with regard to taxes, safety and protection of the environment, including, but not limited to, 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;
- weather, weather-related conditions and other natural phenomena, including, but not limited to, 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; and
- the amount of natural gas we gather, compress, treat, process, transport, store and sell, or the NGLs we produce, fractionate, transport, store and sell, 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 natural gas or NGLs.

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, except as required by applicable securities laws.

Item 1. ***Financial Statements***

DCP MIDSTREAM, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2017	December 31, 2016
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 176	$ 1
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $4 million	541	652
Affiliates	104	134
Other	6	6
Inventories	64	72
Unrealized gains on derivative instruments	31	42
Other	58	87
Total current assets	980	994
Property, plant and equipment, net	9,047	9,069
Goodwill	236	236
Intangible assets, net	135	137
Investments in unconsolidated affiliates	2,988	2,969
Unrealized gains on derivative instruments	4	5
Other long-term assets	189	201
Total assets	$ 13,579	$ 13,611
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 546	$ 677
Affiliates	51	48
Other	14	10
Current maturities of long-term debt	500	500
Unrealized losses on derivative instruments	36	91
Accrued interest	57	72
Accrued taxes	68	49
Accrued wages and benefits	25	72
Capital spending accrual	20	20
Other	73	84
Total current liabilities	1,390	1,623
Long-term debt	4,709	4,907
Unrealized losses on derivative instruments	7	1
Deferred income taxes	28	28
Other long-term liabilities	195	199
Total liabilities	6,329	6,758
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	4,220
Limited partners (143,302,328 and 114,749,848 common units issued and outstanding, respectively)	7,108	2,591
General partner	121	18
Accumulated other comprehensive loss	(9)	(8)
Total partners' equity	7,220	6,821
Noncontrolling interests	30	32
Total equity	7,250	6,853
Total liabilities and equity	$ 13,579	$ 13,611

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31,	
	2017	2016
	(Millions, except per unit amounts)	
Operating revenues:		
Sales of natural gas, NGLs and condensate	$ 1,644	$ 1,119
Sales of natural gas, NGLs and condensate to affiliates	289	175
Transportation, processing and other	157	152
Trading and marketing gains, net	31	18
Total operating revenues	2,121	1,464
Operating costs and expenses:		
Purchases of natural gas and NGLs	1,559	1,032
Purchases of natural gas and NGLs from affiliates	128	103
Operating and maintenance expense	167	179
Depreciation and amortization expense	94	95
General and administrative expense	62	62
Other expense (income), net	10	(87)
Total operating costs and expenses	2,020	1,384
Operating income	101	80
Earnings from unconsolidated affiliates	74	66
Interest expense, net	(73)	(79)
Income before income taxes	102	67
Income tax expense	(1)	(2)
Net income	101	65
Net income attributable to noncontrolling interests	—	—
Net income attributable to partners	101	65
Net loss attributable to predecessor operations	—	7
General partner’s interest in net income	(42)	(31)
Net income allocable to limited partners	$ 59	$ 41
Net income per limited partner unit — basic and diluted	$ 0.41	$ 0.36
Weighted-average limited partner units outstanding — basic and diluted	143.3	114.7

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31,	
	2017	2016
	(Millions)	
Net income	$ 101	$ 65
Other comprehensive income:		
Reclassification of cash flow hedge losses into earnings	1	—
Total other comprehensive income	1	—
Total comprehensive income	102	65
Total comprehensive income attributable to noncontrolling interests	—	—
Total comprehensive income attributable to partners	$ 102	$ 65

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31,	
	2017	2016
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 101	$ 65
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	94	95
Earnings from unconsolidated affiliates	(74)	(66)
Distributions from unconsolidated affiliates	76	87
Net unrealized (gains) losses on derivative instruments	(36)	45
Deferred income tax, net	—	1
Other, net	13	4
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	138	1
Inventories	8	8
Accounts payable	(144)	(55)
Accrued interest	(15)	(15)
Other current assets and liabilities	(20)	(19)
Other long-term assets and liabilities	3	—
Net cash provided by operating activities	144	151
INVESTING ACTIVITIES:		
Capital expenditures	(48)	(57)
Change in restricted cash	—	(7)
Investments in unconsolidated affiliates, net	(20)	(12)
Net cash used in investing activities	(68)	(76)
FINANCING ACTIVITIES:		
Proceeds from long-term debt	—	892
Payments of long-term debt	(195)	(896)
Net change in advances to predecessor from DCP Midstream, LLC	418	50
Distributions to limited partners and general partner	(121)	(121)
Distributions to noncontrolling interests	(2)	(2)
Other	(1)	—
Net cash provided by (used in) financing activities	99	(77)
Net change in cash and cash equivalents	175	(2)
Cash and cash equivalents, beginning of period	1	3
Cash and cash equivalents, end of period	$ 176	$ 1

See accompanying notes to condensed consolidated financial statements.

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

		Partners' Equity				
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
				(Millions)		
Balance, January 1, 2017	$ 4,220	$ 2,591	$ 18	$ (8)	$ 32	$ 6,853
Net income	—	59	42	—	—	101
Other comprehensive income	—	—	—	1	—	1
Net change in parent advances	—	418	—	—	—	418
Acquisition of the DCP Midstream Business	(4,220)	—	—	—	—	(4,220)
Deficit purchase price under carrying value of the Transaction	—	3,097	—	(2)	—	3,095
Issuance of 28,552,480 common units and 2,550,644 general partner units to DCP Midstream, LLC and affiliates	—	1,033	92	—	—	1,125
Distributions to limited partners and general partner	—	(90)	(31)	—	—	(121)
Distributions to noncontrolling interests	—	—	—	—	(2)	(2)
Balance, March 31, 2017	$ —	$ 7,108	$ 121	$ (9)	$ 30	$ 7,250

See accompanying notes to condensed consolidated financial statements.

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

	Partners' Equity					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
			(Millions)			
Balance, January 1, 2016	$ 4,287	$ 2,762	$ 18	$ (8)	$ 33	$ 7,092
Net (loss) income	(7)	41	31	—	—	65
Net change in parent advances	50	—	—	—	—	50
Distributions to limited partners and general partner	—	(90)	(31)	—	—	(121)
Distributions to noncontrolling interests	—	—	—	—	(2)	(2)
Balance, March 31, 2016	$ 4,330	$ 2,713	$ 18	$ (8)	$ 31	$ 7,084

See accompanying notes to condensed consolidated financial statements.

1. Description of Business and Basis of Presentation

DCP Midstream, LP, with its consolidated subsidiaries, or "us", "we", "our" or the "Partnership" is a Delaware limited partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets.

Our Partnership includes our Gathering and Processing and Logistics and Marketing segments. For additional information regarding these segments, see Note 18 - Business Segments.

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 Enbridge, Inc and its affiliates, or Enbridge. Spectra Energy Corp owned 50% of DCP Midstream, LLC prior to the completion of their merger with Enbridge in the first quarter of 2017. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. As of March 31, 2017, DCP Midstream, LLC owned approximately 38.1% of us, including limited partner and general partner interests.

On December 30, 2016, we entered into a Contribution Agreement (the “Contribution Agreement”) with DCP Midstream, LLC and DCP Midstream Operating, LP (the “Operating Partnership”), a 100% owned subsidiary of the Partnership. The transactions and documents contemplated by the Contribution Agreement are collectively referred to hereafter as the “Transaction.” The Transaction closed effective January 1, 2017. Our predecessor results consist of all of the ownership interests of DCP Midstream, LLC in all of its subsidiaries that owned operating assets ("The DCP Midstream Business"), which we acquired from DCP Midstream, LLC on January 1, 2017. This transfer of net assets between entities under common control was 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 The DCP Midstream Business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC’s basis in the net assets contributed. The amount of the purchase price in deficit of DCP Midstream, LLC’s basis in the net assets is recognized as 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. For additional information regarding the Transaction, see Note 3 - Acquisitions.

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.

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 in consolidation.

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 the SEC. Accordingly, these condensed consolidated financial statements reflect all adjustments, consisting 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 presented not misleading. Results of operations for the three months ended March 31, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017. 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 2016 audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2016.

2. New Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2016-15 "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments," or ASU 2016-15 - In August 2016, the FASB issued ASU 2016-15, which amends certain cash flow statement classification guidance. This ASU is effective for interim and annual reporting periods beginning after December 15, 2017, with the option to early adopt for financial statements that have not been issued. We are currently evaluating the potential impact this standard will have on our condensed consolidated statement of cash flows.

FASB ASU, 2016-02 "Leases (Topic 842)," or ASU 2016-02 - In February 2016, the FASB issued ASU 2016-02, which requires lessees to recognize a lease liability on a discounted basis and the right of use of a specified asset at the commencement date for all leases. This ASU is effective for interim and annual reporting periods beginning after December 15, 2018, with the option to early adopt for financial statements that have not been issued. We are currently evaluating the potential impact this standard will have on our condensed consolidated financial statements and related disclosures.

FASB ASU, 2015-16 "Business Combinations (Topic 805)," or ASU 2015-16 - In September 2015, the FASB issued ASU 2015-16, which requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. This ASU is effective for interim and annual reporting periods beginning after December 15, 2016. The company has adopted the ASU and it did not have any impact on our condensed consolidated results of operations, cash flows and financial position.

FASB ASU *2014-09 "Revenue from Contracts with Customers (Topic 606)," or ASU 2014-09 and related interpretations and amendments* - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification Topic 605 "Revenue Recognition." This ASU is effective for annual reporting periods beginning after December 15, 2017, with the option to adopt as early as annual reporting periods beginning after December 15, 2016. We plan to adopt this ASU using the modified retrospective method. The initial cumulative effect will be recognized at the date of adoption. Our evaluation of ASU 2014-09 is ongoing and not complete. The FASB has issued and may issue in the future, interpretative guidance, which may cause our evaluation to change. Accordingly, at this time we cannot estimate the impact upon adoption.

3. Acquisitions

On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash (together the "Contributions"). In consideration of the Partnership's receipt of the Contributions, (i) the Partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to the General Partner in a private placement and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC's debt. This represents a transaction between entities under common control and a change in reporting entity.

Pursuant to the Contribution Agreement, DCP Midstream, LLC agreed to cause the General Partner to enter into Amendment No. 3 (the "Third Amendment to the Partnership Agreement") to the Second Amended and Restated Agreement of Limited Partnership of the Partnership, dated November 1, 2006, as amended (the "Partnership Agreement"). On January 1, 2017, the General Partner, in its capacity as the general partner of the Partnership, entered into the Third Amendment to the Partnership Agreement. The Third Amendment to the Partnership Agreement includes terms that amend the Partnership Agreement to cause the incentive distributions payable to the holders of the Partnership's incentive distribution rights with respect to the fiscal years 2017, 2018 and 2019 to, in certain circumstances, be reduced in an amount up to $100 million per fiscal year as necessary to provide that the distributable cash flow of the Partnership (as adjusted) during such year meets or exceeds the amount of distributions made by the Partnership (as adjusted) to the partners of the Partnership with respect to such year.

4. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

Pursuant to the Contribution Agreement, on January 1, 2017, the Partnership entered into the Services and Employee Secondment Agreement (the "Services Agreement"), which replaced the services agreement between the Partnership and DCP Midstream, LLC, dated February 14, 2013, as amended. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for costs, expenses, and expenditures incurred or payments made on our behalf for general and administrative functions including, but not limited to, legal, accounting, compliance, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, benefit plan maintenance and administration, credit, payroll, internal audit, taxes and engineering, as well as salaries and benefits of seconded employees, insurance coverage and claims, capital expenditures, maintenance and repair costs and taxes. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for costs, expenses and expenditures incurred or payments made on our behalf.

Phillips 66 and CPChem

We sell a portion of our NGLs to Phillips 66 and Chevron Phillips Chemical LLC, or CPChem. In addition, we purchase NGLs from CPChem. CPChem is owned 50% by Phillips 66, and is considered a related party. Approximately 26% of our NGL production was committed to Phillips 66 and CPChem as of March 31, 2017. The primary production commitment on certain contracts began a ratable wind down period in December 2014 and expires in January 2019. We anticipate continuing to purchase and sell commodities with Phillips 66 and CPChem in the ordinary course of business.

Enbridge and its Affiliates including Spectra Energy Corp

We sell a portion of our natural gas and NGLs to Enbridge. In addition, we purchase natural gas and NGL products from Enbridge. We anticipate continuing to purchase commodities and provide services to Enbridge in the ordinary course of business.

Unconsolidated Affiliates

We, along with other third party shippers, have entered into 15-year transportation agreements, with Sand Hills Pipeline, LLC, or Sand Hills, Southern Hills Pipeline, LLC, or Southern Hills, Front Range Pipeline LLC, or Front Range, and Texas Express Pipeline LLC, or Texas Express. Under the terms of these 15-year agreements, which commenced at each of the pipelines' respective in-service dates and expire in 2028 and 2029, we have committed to transport minimum throughput volumes at rates defined in each of the pipelines' respective tariffs.

Under the terms of the Sand Hills LLC Agreement and the Southern Hills LLC Agreement, or the Sand Hills and Southern Hills LLC Agreements, Sand Hills and Southern Hills are required to reimburse us for any direct costs or expenses (other than general and administration services) which we incur on behalf of Sand Hills and Southern Hills. Additionally, Sand Hills and Southern Hills each pay us an annual service fee of $5 million, for centralized corporate functions provided by us as operator of Sand Hills and Southern Hills, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual service fee, there is no limit on the reimbursements Sand Hills and Southern Hills make to us under the Sand Hills and Southern Hills LLC Agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

We also sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, and provide gathering and transportation services to other unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(Millions)	
Phillips 66 (including CPChem):		
Sales of natural gas and NGLs	$ 274	$ 171
Purchases of natural gas and NGLs	$ 7	$ —
Operating and maintenance	$ 1	$ —
Enbridge (including Spectra Energy Corp):		
Sales of natural gas and NGLs	$ 5	$ —
Purchases of natural gas and NGLs	$ 8	$ 10
Operating and maintenance	$ 1	$ 1
Unconsolidated affiliates:		
Sales of natural gas and NGLs	$ 10	$ 4
Purchases of natural gas and NGLs	$ 113	$ 93
Transportation, processing and other	$ 1	$ 1

We had balances with affiliates as follows:

	March 31, 2017	December 31, 2016
	(Millions)	
Phillips 66 (including CPChem):		
Accounts receivable	$ 85	$ 115
Accounts payable	$ 4	$ 4
Other assets	$ —	$ 2
Enbridge (including Spectra Energy Corp):		
Accounts receivable	$ 5	$ 1
Accounts payable	$ 3	$ 3
Other assets	$ —	$ 1
Other liabilities	$ 2	$ 1
Unconsolidated affiliates:		
Accounts receivable	$ 14	$ 18
Accounts payable	$ 44	$ 41
Other assets	$ 3	$ 5

5. Inventories

Inventories were as follows:

	March 31, 2017	December 31, 2016
	(Millions)	
Natural gas	$ 32	$ 28
NGLs	32	44
Total inventories	$ 64	$ 72

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 and NGLs in the condensed consolidated statements of operations. We recognized no lower of cost or market adjustments during the three months ended March 31, 2017 and $3 million during the three months ended March 31, 2016.

6. Property, Plant and Equipment

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

	Depreciable Life	March 31, 2017	December 31, 2016
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$ 8,568	$ 8,560
Processing, storage and terminal facilities	35 — 60 Years	5,144	5,134
Other	3 — 30 Years	506	502
Construction work in progress		216	171
Property, plant and equipment		14,434	14,367
Accumulated depreciation		(5,387)	(5,298)
Property, plant and equipment, net		$ 9,047	$ 9,069

Interest capitalized on construction projects was $1 million and less than $1 million for the three months ended March 31, 2017 and 2016, respectively.

Depreciation expense was $92 million and $92 million for the three months ended March 31, 2017 and 2016, respectively.

Asset Retirement Obligations - As of March 31, 2017 and December 31, 2016, we had asset retirement obligations of $126 million and $124 million, respectively, included in other long-term liabilities in the condensed consolidated balance sheets. Accretion expense was $2 million for the three months ended March 31, 2017 and 2016, respectively.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

7. Goodwill and Intangible Assets

The carrying amount of goodwill in each of our reporting segments was as follows:

	Three Months Ended March 31, 2017 (millions)		
	Gathering and Processing	Logistics and Marketing	Total
Balance, beginning of period	$ 164	$ 72	$ 236
Balance, end of period	$ 164	$ 72	$ 236

We will perform our annual goodwill assessment during the third quarter of 2017 at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

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

	March 31, 2017	December 31, 2016
	(millions)	
Gross carrying amount	$ 410	$ 410
Accumulated amortization	(153)	(151)
Accumulated impairment	(122)	(122)
Intangible assets, net	$ 135	$ 137

For the three months ended March 31, 2017 and 2016, we recorded amortization expense of $2 million and $3 million, respectively. As of March 31, 2017, the remaining amortization periods ranged from approximately 1 years to approximately 18 years, with a weighted-average remaining period of approximately 14 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(millions)
2017	$ 8
2018	11
2019	11
2020	11
2021	11
Thereafter	83
Total	$ 135

8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of March 31, 2017	Carrying Value as of December 31, 2016
		(Millions)	
DCP Sand Hills Pipeline, LLC	66.67%	$ 1,531	$ 1,507
Discovery Producer Services LLC	40.00%	381	385
DCP Southern Hills Pipeline, LLC	66.67%	753	754
Front Range Pipeline LLC	33.33%	166	165
Texas Express Pipeline LLC	10.00%	93	93
Panola Pipeline Company, LLC	15.00%	24	25
Mont Belvieu Enterprise Fractionator	12.50%	22	23
Mont Belvieu 1 Fractionator	20.00%	10	10
Other	Various	8	7
Total investments in unconsolidated affiliates		$ 2,988	$ 2,969

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(Millions)	
DCP Sand Hills Pipeline, LLC	$ 31	$ 25
Discovery Producer Services LLC	20	15
DCP Southern Hills Pipeline, LLC	11	12
Front Range Pipeline LLC	4	5
Texas Express Pipeline LLC	2	2
Mont Belvieu Enterprise Fractionator	3	4
Mont Belvieu 1 Fractionator	1	3
Other	2	—
Total earnings from unconsolidated affiliates	$ 74	$ 66

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

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(Millions)	
Statements of operations:		
Operating revenue	$ 337	$ 307
Operating expenses	$ 148	$ 119
Net income	$ 188	$ 186

	March 31, 2017	December 31, 2016
	(Millions)	
Balance sheets:		
Current assets	$ 200	$ 232
Long-term assets	5,256	5,274
Current liabilities	(134)	(156)
Long-term liabilities	(202)	(205)
Net assets	$ 5,120	$ 5,145

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an "exit price" methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, 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 11 - Risk Management and Hedging Activities.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy and are categorized in their entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement. 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 exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices 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 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.

We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using 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 periodically use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our fixed-rate debt for floating rate debt or floating rate debt for fixed-rate debt. The 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 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 other 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 March 31, 2017 and December 31, 2016, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	March 31, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$ 8	$ 15	$ 8	$ 31	$ 5	$ 28	$ 9	$ 42
Short-term investments (b)	$ 175	$ —	$ —	$ 175	$ —	$ —	$ —	$ —
Long-term assets:								
Commodity derivatives (c)	$ 1	$ 1	$ 2	$ 4	$ —	$ —	$ 5	$ 5
Current liabilities:								
Commodity derivatives (d)	$ (7)	$ (21)	$ (8)	$ (36)	$ (11)	$ (57)	$ (23)	$ (91)
Long-term liabilities:								
Commodity derivatives (e)	$ —	$ (4)	$ (3)	$ (7)	$ (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 or out of Level 1 and Level 2. During the three months ended March 31, 2017 and 2016, there were no transfers into or 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 would reflect 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 March 31, 2017 (a):				
Beginning balance	$ 9	$ 5	$ (23)	$ —
Net unrealized gains (losses) included in earnings (b)	2	(3)	8	(3)
Settlements	(3)	—	7	—
Ending balance	$ 8	$ 2	$ (8)	$ (3)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 2	$ (2)	$ 8	$ (3)
Three months ended March 31, 2016 (a):				
Beginning balance	$ 35	$ 4	$ (23)	$ (6)
Net unrealized gains (losses) included in earnings (b)	1	(2)	—	3
Settlements	(27)	—	6	—
Ending balance	$ 9	$ 2	$ (17)	$ (3)
Net unrealized (losses) gains on derivatives still held included in earnings (b)	$ —	$ (2)	$ —	$ 3

(a) There were no purchases, issuances or sales of derivatives or transfers into/out of Level 3 for the three months ended March 31, 2017 and 2016.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains (losses), net.

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.

	March 31, 2017		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$ 9	$0.25-$1.15	Per gallon
Natural gas	$ 1	$2.61-$2.87	Per MMBtu
Liabilities			
NGLs	$ (8)	$0.20-$1.15	Per gallon
Natural gas	$ (3)	$2.09-$2.72	Per MMBtu

Estimated Fair Value of Financial Instruments

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

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

The fair value of our interest rate swaps, if any, 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 any, 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 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 and junior subordinated notes based on quotes obtained from bond dealers. We determine the fair value of borrowings under our revolving credit facility based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of March 31, 2017 and December 31, 2016, the carrying value and fair value of our total debt, including current maturities, were as follows:

	March 31, 2017		December 31, 2016	
	Carrying Value (a)	Fair Value	Carrying Value (a)	Fair Value
	(Millions)			
Total debt	$ 5,235	$ 5,307	$ 5,430	$ 5,395

(a) Excludes unamortized issuance costs.

10. Debt

	March 31, 2017	December 31, 2016
	(Millions)	
Senior notes:		
Issued November 2012, interest at 2.500% payable semi-annually, due December 2017	$ 500	$ 500
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	450	450
Issued March 2014, interest at 2.700% payable semi-annually, due April 2019	325	325
Issued March 2010, interest at 5.350% payable semiannually, due March 2020 (a)	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued March 2012, interest at 4.950% payable semi-annually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semi-annually, due March 2023	500	500
Issued August 2000, interest at 8.125% payable semi-annually, due August 2030 (a)	300	300
Issued October 2006, interest at 6.450% payable semi-annually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semi-annually, due September 2037	450	450
Issued March 2014, interest at 5.600% payable semi-annually, due April 2044	400	400
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semi-annually, due May 2043	550	550
Credit facility with financial institutions:		
Revolving credit facility, weighted-average variable interest rate of 2.010%, as of December 31, 2016, due May 2019	—	195
Fair value adjustments related to interest rate swap fair value hedges (a)	24	24
Unamortized issuance costs	(26)	(23)
Unamortized discount	(14)	(14)
Total debt	5,209	5,407
Current maturities of long-term debt	500	500
Total long-term debt	$ 4,709	$ 4,907

(a) The swaps associated with this debt were previously terminated. The remaining long-term fair value of approximately $24 million related to the swaps is being amortized as a reduction to interest expense through 2019, 2020 and 2030, the original maturity dates of the debt.

Credit Facility with Financial Institutions

In February 2017, we further amended our $1.25 billion senior unsecured revolving credit agreement that matures on May 1, 2019, or the Credit Agreement, to increase the aggregate commitments under the unsecured revolving credit facility to approximately $1.4 billion. The Credit Agreement is used for working capital requirements and other general partnership purposes including acquisitions.

The Credit Agreement allows for unrestricted cash and cash equivalents to be netted against consolidated indebtedness for purposes of calculating the Partnership's Consolidated Leverage Ratio (as defined in the Credit Agreement). Additionally, under the Credit Agreement, the maximum Consolidated Leverage Ratio of the Partnership as of the end of any fiscal quarter shall not exceed: (a) 5.75 to 1.0 for the quarters ending March 31, 2017 through December 31, 2017, (b) 5.50 to 1.0 for the quarter ending March 31, 2018, (c) 5.25 to 1.0 for the quarter ending June 30, 2018, and (d) 5.00 to 1.0 for the quarters thereafter; provided that, if there is a Qualified Acquisition (as defined in the Credit Agreement) during any fiscal quarter ending June 30, 2018 or thereafter, the maximum Consolidated Leverage Ratio shall not exceed 5.50 to 1.0 at the end of such quarter and at the end of the two fiscal quarters immediately thereafter.

Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. Indebtedness under the Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.45% based on our current credit rating; or (2) (a) the base rate which shall be the higher of the prime rate, the Federal Funds rate, plus 0.50% or the LIBOR Market Index rate, plus 1%, plus (b) an applicable margin of 0.45% based on our current credit rating. The Credit Agreement incurs an annual facility fee of 0.3% based on our current credit rating. This fee is paid on drawn and undrawn portions of the approximately $1.4 billion revolving credit facility.

As of March 31, 2017, we had unused borrowing capacity of $1,374 million, net of $24 million of letters of credit, under the Credit Agreement. Our borrowing capacity may be limited by financial covenants set forth in the Credit Agreement. The financial covenants set forth in the Credit Agreement limit the Partnership's ability to incur incremental debt by $1,106 million as of March 31, 2017. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the May 1, 2019 maturity date.

Senior Notes and Junior Subordinated Notes

Our senior notes and junior subordinated notes, collectively referred to as our debt securities, mature and become payable on the respective due dates, and are not subject to any sinking fund or mandatory redemption provisions. The senior notes are senior unsecured obligations that are guaranteed by the Partnership and rank equally in a right of payment with our other senior unsecured indebtedness, including indebtedness under our credit agreement, and the junior subordinated notes are unsecured and rank subordinate in right of payment to all of our existing and future senior indebtedness. The debt securities include an optional redemption whereby we may elect to redeem the notes, in whole or in part from time-to-time for a premium. Additionally, we may defer the payment of all or part of the interest on the junior subordinated notes for one or more periods up to five consecutive years. The underwriters' fees and related expenses are recorded in our condensed consolidated balance sheets within the carrying amount of long-term debt and will be amortized over the term of the notes.

	Debt Maturities
	(Millions)
2018	$ —
2019	775
2020	600
2021	500
2022	350
Thereafter	2,500
Total	$ 4,725

11. Risk Management and Hedging Activities

Our day-to-day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with either physical or financial transactions. We have established a comprehensive 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

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized below.

Natural Gas Asset Based Trading and Marketing

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 our natural gas storage facility 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 into 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 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 March 31, 2017.

Commodity 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 may 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. Our derivative financial instruments used to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices extend through the first quarter of 2018. The commodity derivative instruments used for our hedging programs 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 may use crude oil swaps to mitigate a portion of the commodity price risk exposure for 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. When our crude oil swaps become short-term in nature, certain crude oil derivatives may be converted to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange floating price risk for a fixed price. The type of instrument used to mitigate a portion of the risk may vary depending on our risk management objectives. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our condensed consolidated statements of operations as trading and marketing gains, net.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments 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.

We employ established risk limits, policies and procedures to manage risks associated with our natural gas asset based trading and marketing and NGL proprietary trading.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to convert our floating rate debt to fixed-rate debt or to convert our fixed-rate debt to floating rate debt. Our primary goals include: (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates.

We previously had interest rate cash flow hedges and fair value hedges in place that were terminated. As the underlying transactions impact earnings, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to interest expense, net from 2022 through 2030 and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense, net from 2019 through 2030, the original maturity dates of the debt.

Credit Risk

Our principal customers range from large, natural gas marketers to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 26% of our NGL production was committed to Phillips 66 and CPChem as of March 31, 2017. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

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 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.

- Our ISDA counterparties generally have collateral thresholds of zero, requiring us to fully collateralize any commodity contracts in a net liability position, when our credit rating is below investment grade.
- 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 Credit Agreement. As of March 31, 2017, 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 March 31, 2017, all of our individual commodity derivative contracts that contain credit-risk related contingent features were in a net asset position. If we were required to net settle our position with an individual counterparty, due to a credit-risk related event, our ISDA contracts may permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of March 31, 2017, we were not required to post additional collateral or offset net liability contracts with contracts in a net asset position because all of our commodity derivative contracts that contain credit-risk related contingent features were in a net asset position.

Collateral

As of March 31, 2017, we had cash deposits of $38 million, included in other current assets in our condensed consolidated balance sheets, and letters of credit of $13 million with counterparties to secure our obligations to provide future services or to perform under financial contracts. Additionally, as of March 31, 2017, we held cash of $5 million, included in other current liabilities in our condensed consolidated balance sheet, related to cash postings by third parties and letters of credit of $31 million from counterparties to secure their future performance under financial or physical contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, services, trading and hedging contracts. In many cases, we and our counterparties have publicly disclosed credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

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:

	March 31, 2017			December 31, 2016		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments	Net Amount
	(Millions)					
Assets:						
Commodity derivatives	$ 35	$ —	$ 35	$ 47	$ —	$ 47
Liabilities:						
Commodity derivatives	$ (43)	$ —	$ (43)	$ (92)	$ —	$ (92)

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 March 31, 2017 and December 31, 2016.

Balance Sheet Line Item	March 31, 2017	December 31, 2016	Balance Sheet Line Item	March 31, 2017	December 31, 2016
	(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	$ 31	$ 42	Unrealized losses on derivative instruments — current	$ (36)	$ (91)
Unrealized gains on derivative instruments — long-term	4	5	Unrealized losses on derivative instruments — long-term	(7)	(1)
Total	$ 35	$ 47	Total	$ (43)	$ (92)

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 March 31, 2017:

	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)	$ (3)	$ (6)	$ 1	$ (8)
Losses reclassified from AOCI to earnings — effective portion	1	—	—	1
Deficit purchase price under carrying value of the Transaction	$ (2)	$ —	$ —	$ (2)
Net deferred (losses) gains in AOCI (ending balance)	$ (4)	$ (6)	$ 1	$ (9)

(a) Relates to Discovery, an unconsolidated affiliate.

For the three months ended March 31, 2017, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in trading and marketing gains, net or interest expense in our condensed consolidated statements of operations. For the three months ended March 31, 2017, no derivative losses were reclassified from

AOCI to trading and marketing gains, net or 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 three months ended March 31, 2016:

	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)	$ (3)	$ (6)	$ 1	$ (8)
Net deferred (losses) gains in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)

(a) Relates to Discovery, an unconsolidated affiliate.

For the three months ended March 31, 2016, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in trading and marketing gains or losses, net or interest expense in our condensed consolidated statements of operations. For the three months ended March 31, 2016, no derivative losses were reclassified from AOCI to trading and marketing gains or losses, net or interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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

Commodity Derivatives: Statements of Operations Line Item	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(Millions)	
Realized (losses) gains	$ (5)	$ 63
Unrealized gains (losses)	36	(45)
Trading and marketing gains, net	$ 31	$ 18

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.

	March 31, 2017			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net (Short) Long Position (MMBtu)	Net (Short) Long Position (Bbls)	Net Long Position (MMBtu)
2017	(1,004,000)	(48,928,700)	(16,786,124)	5,662,500
2018	(416,000)	50,000	(156,537)	3,192,500
2019	(40,000)	—	(2,203)	—
2020	(50,000)	—	240,000	—

	March 31, 2016			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Short Position (MMBtu)	Net (Short) Long Position (Bbls)	Net (Short) Long Position (MMBtu)
2016	(1,060,000)	(20,743,700)	(18,260,483)	(1,750,000)
2017	(292,000)	(13,717,500)	(2,467,393)	5,670,000
2018	—	—	145,500	—

12. Partnership Equity and Distributions

In January 2017, we issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to the General Partner in a private placement as consideration for the Transaction that closed on January 1, 2017. For additional information regarding the Transaction, see Note 3 - Acquisitions.

During the three months ended March 31, 2017 and 2016, we issued no common units pursuant to our 2014 equity distribution agreement. As of March 31, 2017, approximately $349 million of common units remained available for sale pursuant to our 2014 equity distribution agreement.

The following table presents our cash distributions paid in 2017 and 2016:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
February 14, 2017	$ 0.78	$ 121
November 14, 2016	$ 0.78	$ 120
August 12, 2016	$ 0.78	$ 121
May 13, 2016	$ 0.78	$ 121
February 12, 2016	$ 0.78	$ 121

13. Equity-Based Compensation

Under DCP Midstream, LLC's Long-Term Incentive Plan ("DCP Midstream LTIP"), awards may be granted to key employees. The DCP Midstream LTIP provides for the grant of Strategic Performance Units ("SPUs") and Phantom Units. The SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of Phillips 66, Enbridge and the Partnership. Each award provides for the grant of dividend or distribution equivalent rights, or DERs. The DCP Midstream LTIP is administered by the compensation committee of DCP Midstream, LLC's board of directors. All awards are subject to cliff vesting.

Since we have the intent and ability to settle certain awards within our control in units, we classify them as equity awards based on their fair value. The fair value of our equity awards is determined based on the closing price of our common units on the grant date. Compensation expense on equity awards is recognized ratably over each vesting period. We account for other awards which are subject to settlement in cash, including DERs, as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date.

Liability classified share-based compensation cost is remeasured at each reporting date at fair value, based on the closing security price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award.

Equity-based compensation expense was $3 million for the three months ended March 31, 2017 and 2016, respectively.

The following table presents the fair value of unvested unit-based awards related to the strategic performance units and phantom units:

	Vesting Period (years)	Unrecognized Compensation Expense at March 31, 2017 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:				
Strategic Performance Units (SPUs)	3	5	0%-11%	2
Phantom Units	1-3	4	0%-11%	2

Strategic Performance Units - The number of SPUs that will ultimately vest range in value of up to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. The DERs are paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2017	233,311	$ 44.41	$ 45.86
Granted	—	—	—
Forfeited	—	—	—
Vested	—	—	—
Outstanding at March 31, 2017	233,311	$ 44.41	$ 45.86
Expected to vest	219,844	$ 44.35	$ 45.98

The estimate of SPUs that are expected to vest is based on highly subjective assumptions that could change over time, including the expected forfeiture rate and achievement of performance targets.

Phantom Units - The DERs are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2017	207,317	$ 46.80	$ 45.97
Granted	—	—	—
Forfeited	—	—	—
Vested	—	—	—
Outstanding at March 31, 2017	207,317	$ 46.80	$ 45.97
Expected to vest	185,785	$ 46.72	$ 45.90

14. Benefits

We do not have our own employees. The employees supporting our operations are employees of DCP Midstream, LLC, for which we incur charges under the Services Agreement. All DCP Midstream, LLC employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which a range of 4% to 7% of each eligible employee's qualified earnings is contributed, based on years of service. The 401(k) plan has an automatic enrollment feature, meaning all new employees are enrolled at a 6% contribution level. Employees can opt out of this contribution level or change it at any time. Additionally, DCP Midstream, LLC matches employees' contributions in the 401(k) plan up to 6% of qualified earnings. During the three months ended March 31, 2017 and 2016, we expensed plan contributions of $8 million, and $9 million, respectively.

DCP Midstream, LLC offers certain eligible executives the opportunity to participate in the Executive Deferred Compensation Plan, or EDC Plan. The EDC Plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The EDC Plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant's behalf.

15. 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 awards under the LTIP. The dilutive effect of unit-based awards was 198 and 1,604 equivalent units during the three months ended March 31, 2017 and 2016 respectively.

16. Income Taxes

We are structured as a master limited partnership with sufficient qualifying income, which is a pass-through entity for federal income tax purposes. Accordingly, we had no federal income tax expense for the three months ended March 31, 2017 and 2016, respectively.

The State of Texas imposes a margin tax that is assessed at 0.75% of taxable margin apportioned to Texas for the three months ended March 31, 2017 and 2016, respectively.

Income tax expense consists of the following:

	Three months ended March 31, 2017	Three months ended March 31, 2016
	(Millions)	
Current state income tax expense	$ 1	$ 1
Deferred federal income tax expense	—	1
Total income tax expense	$ 1	$ 2

We had net long-term deferred tax liabilities of $28 million as of both March 31, 2017 and December 31, 2016, included in other long-term liabilities on the condensed consolidated balance sheets. These state deferred tax liabilities relate to our Texas operations and are primarily associated with depreciation related to property, plant and equipment.

Our effective tax rate differs from statutory rates, primarily due to being structured as a master limited partnership, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states.

17. 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 results of operations, financial position, or cash flow.

In January 2016, we reached a settlement with a large producer in the DJ basin and received a cash payment of $89 million, a dedication of a portion of the producer's production in the DJ Basin under a life of lease agreement and a 15 year dedication of natural gas liquids from the producer and its affiliates to the Sand Hills pipeline in the Delaware basin of the Permian region. The cash consideration was received in February 2016, and we recorded other income, net of $2 million in legal fees, in the condensed consolidated statement of operations for the three months ended March 31, 2016.

Insurance — Our insurance coverage is carried with third-party insurers and with an affiliate of Phillips 66. Our insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (6) insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, fractionating, 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, in some cases, local levels that relate to worker safety, air and water quality, solid and hazardous 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, worker safety standards, and safety standards applicable to our various facilities. In addition, there is increasing focus (i) 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 and the resulting supply of NGLs, (ii) from federal regulatory agencies regarding pipeline system safety which could impose additional regulatory burdens and increase the cost of our operations, and (iii) from state and federal regulatory officials regarding the emission of greenhouse gases which could impose regulatory burdens and increase the cost of our operations. 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 existing laws and regulations will not have a material adverse effect on our results of operations, financial position or cash flows.

Operating Leases — We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $8 million and $9 million during the three months ended March 31, 2017 and 2016, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments
	(millions)
2017	$ 46
2018	37
2019	34
2020	29
2021	21
Thereafter	42
Total minimum rental payments	$ 209

18. Business Segments

Concurrent with the completion of the Transaction in the first quarter of 2017, management reevaluated our reportable segments and determined that our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Segment information for prior periods has been retrospectively adjusted to furnish comparative information similar to the pooling method to reflect these reportable segments. 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. Our reportable segments include operating segments that have been aggregated based on the nature of the products and services provided. Gross margin is a performance measure utilized by management to monitor the operations of each segment. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies in our Annual Report on Form 10-K for the year ended December 31, 2016.

Our Gathering and Processing segment consists of gathering, compressing, treating, processing natural gas, producing and fractionating NGLs, and recovering and selling condensate. Our Logistics and Marketing segment includes transporting, trading, marketing, and storing natural gas and NGLs, fractionating NGLs, and wholesale propane logistics. The remainder of our business operations is presented as “Other,” and consists of unallocated corporate costs. Elimination of inter-segment transactions are reflected in the eliminations column.

The following tables set forth our segment information:

Three Months Ended March 31, 2017:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 1,359	$ 1,927	$ —	$ (1,165)	$ 2,121
Gross margin (a)	$ 376	$ 58	$ —	$ —	$ 434
Operating and maintenance expense	(153)	(9)	(5)	—	(167)
Depreciation and amortization expense	(85)	(4)	(5)	—	(94)
General and administrative expense	(6)	(3)	(53)	—	(62)
Other expense	—	(9)	(1)	—	(10)
Earnings from unconsolidated affiliates	20	54	—	—	74
Interest expense	—	—	(73)	—	(73)
Income tax expense	—	—	(1)	—	(1)
Net income (loss)	$ 152	$ 87	$ (138)	$ —	$ 101
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income (loss) attributable to partners	$ 152	$ 87	$ (138)	$ —	$ 101
Non-cash derivative mark-to-market (b)	$ 31	$ 5	$ —	$ —	$ 36
Non-cash lower of cost or market adjustments	$ —	$ —	$ —	$ —	$ —
Capital expenditures	$ 43	$ 1	$ 4	$ —	$ 48
Investments in unconsolidated affiliates, net	$ —	$ 20	$ —	$ —	$ 20

Three Months Ended March 31, 2016:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 936	$ 1,264	$ —	$ (736)	$ 1,464
Gross margin (a)	$ 269	$ 60	$ —	$ —	$ 329
Operating and maintenance expense	(161)	(10)	(8)	—	(179)
Depreciation and amortization expense	(86)	(4)	(5)	—	(95)
General and administrative expense	(4)	(3)	(55)	—	(62)
Other income	87	—	—	—	87
Earnings from unconsolidated affiliates	15	51	—	—	66
Interest expense	—	—	(79)	—	(79)
Income tax expense	—	—	(2)	—	(2)
Net income (loss)	$ 120	$ 94	$ (149)	$ —	$ 65
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income (loss) attributable to partners	$ 120	$ 94	$ (149)	$ —	$ 65
Non-cash derivative mark-to-market (b)	$ (39)	$ (6)	$ —	$ —	$ (45)
Non-cash lower of cost or market adjustments	$ 3	$ —	$ —	$ —	$ 3
Capital expenditures	$ 50	$ 2	$ 5	$ —	$ 57
Investments in unconsolidated affiliates, net	$ —	$ 12	$ —	$ —	$ 12

	March 31, 2017	December 31, 2016
	(Millions)	
Segment long-term assets:		
Gathering and Processing	$ 9,035	$ 9,053
Logistics and Marketing	3,288	3,278
Other (c)	276	286
Total long-term assets	12,599	12,617
Current assets	980	994
Total assets	$ 13,579	$ 13,611

(a) Gross margin consists of total operating revenues, including trading and marketing gains and losses, less purchases of natural gas and NGLs. Gross margin is viewed as a non-GAAP financial 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) Other long-term assets not allocable to segments consist of unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

19. Supplemental Cash Flow Information

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 87	$ 91
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$ 46	$ 13
Other non-cash changes in property, plant and equipment	$ —	$ (2)
Issuance of common and general partner units in the Transaction	$ 1,125	$ —
Deficit purchase price in the Transaction	$ 3,097	$ —

20. Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream, 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, LP's results on a consolidated basis. 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
March 31, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 175	$ 1	$ —	$ 176
Accounts receivable, net	—	—	651	—	651
Inventories	—	—	64	—	64
Other	—	—	89	—	89
Total current assets	—	175	805	—	980
Property, plant and equipment, net	—	—	9,047	—	9,047
Goodwill and intangible assets, net	—	—	371	—	371
Advances receivable — consolidated subsidiaries	2,832	2,297	—	(5,129)	—
Investments in consolidated subsidiaries	4,388	7,182	—	(11,570)	—
Investments in unconsolidated affiliates	—	—	2,988	—	2,988
Other long-term assets	—	—	193	—	193
Total assets	$ 7,220	$ 9,654	$ 13,404	$ (16,699)	$ 13,579
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 57	$ 833	$ —	$ 890
Current maturities of long-term debt	—	500	—	—	500
Advances payable — consolidated subsidiaries	—	—	5,129	(5,129)	—
Long-term debt	—	4,709	—	—	4,709
Other long-term liabilities	—	—	230	—	230
Total liabilities	—	5,266	6,192	(5,129)	6,329
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	7,220	4,392	7,187	(11,570)	7,229
Accumulated other comprehensive loss	—	(4)	(5)	—	(9)
Total partners' equity	7,220	4,388	7,182	(11,570)	7,220
Noncontrolling interests	—	—	30	—	30
Total equity	7,220	4,388	7,212	(11,570)	7,250
Total liabilities and equity	$ 7,220	$ 9,654	$ 13,404	$ (16,699)	$ 13,579

	Condensed Consolidating Balance Sheet December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ —	$ 1	$ —	$ 1
Accounts receivable, net	—	—	792	—	792
Inventories	—	—	72	—	72
Other	—	—	129	—	129
Total current assets	—	—	994	—	994
Property, plant and equipment, net	—	—	9,069	—	9,069
Goodwill and intangible assets, net	—	—	373	—	373
Advances receivable — consolidated subsidiaries	2,953	2,760	—	(5,713)	—
Investments in consolidated subsidiaries	3,868	6,587	—	(10,455)	—
Investments in unconsolidated affiliates	—	—	2,969	—	2,969
Other long-term assets	—	—	206	—	206
Total assets	$ 6,821	$ 9,347	$ 13,611	$ (16,168)	$ 13,611
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 72	$ 1,051	$ —	$ 1,123
Current maturities of long-term debt	—	500	—	—	500
Advances payable — consolidated subsidiaries	—	—	5,713	(5,713)	—
Long-term debt	—	4,907	—	—	4,907
Other long-term liabilities	—	—	228	—	228
Total liabilities	—	5,479	6,992	(5,713)	6,758
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	6,821	3,871	6,592	(10,455)	6,829
Accumulated other comprehensive loss	—	(3)	(5)	—	(8)
Total partners' equity	6,821	3,868	6,587	(10,455)	6,821
Noncontrolling interests	—	—	32	—	32
Total equity	6,821	3,868	6,619	(10,455)	6,853
Total liabilities and equity	$ 6,821	$ 9,347	$ 13,611	$ (16,168)	$ 13,611

Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 1,933	$ —	$ 1,933
Transportation, processing and other	—	—	157	—	157
Trading and marketing gains, net	—	—	31	—	31
Total operating revenues	—	—	2,121	—	2,121
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	1,687	—	1,687
Operating and maintenance expense	—	—	167	—	167
Depreciation and amortization expense	—	—	94	—	94
General and administrative expense	—	—	62	—	62
Other expense	—	—	10	—	10
Total operating costs and expenses	—	—	2,020	—	2,020
Operating income	—	—	101	—	101
Interest expense	—	(73)	—	—	(73)
Income from consolidated subsidiaries	101	174	—	(275)	—
Earnings from unconsolidated affiliates	—	—	74	—	74
Income before income taxes	101	101	175	(275)	102
Income tax expense	—	—	(1)	—	(1)
Net income	101	101	174	(275)	101
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income attributable to partners	$ 101	$ 101	$ 174	$ (275)	$ 101

Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 31, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$ 101	$ 101	$ 174	$ (275)	$ 101
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	102	102	174	(276)	102
Total comprehensive income attributable to noncontrolling interests	—	—	—	—	—
Total comprehensive income attributable to partners	$ 102	$ 102	$ 174	$ (276)	$ 102

Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 1,294	$ —	$ 1,294
Transportation, processing and other	—	—	152	—	152
Trading and marketing gains, net	—	—	18	—	18
Total operating revenues	—	—	1,464	—	1,464
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	1,135	—	1,135
Operating and maintenance expense	—	—	179	—	179
Depreciation and amortization expense	—	—	95	—	95
General and administrative expense	—	—	62	—	62
Other income	—	—	(87)	—	(87)
Total operating costs and expenses	—	—	1,384	—	1,384
Operating income	—	—	80	—	80
Interest expense, net	—	(79)	—	—	(79)
Income from consolidated subsidiaries	65	144	—	(209)	—
Earnings from unconsolidated affiliates	—	—	66	—	66
Income before income taxes	65	65	146	(209)	67
Income tax expense	—	—	(2)	—	(2)
Net income	65	65	144	(209)	65
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income attributable to partners	$ 65	$ 65	$ 144	$ (209)	$ 65

Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 65	$ 65	$ 144	$ (209)	$ 65
Total other comprehensive income	— —	— —	— —	— —	—
Total comprehensive income	65	65	144	(209)	65
Total comprehensive income attributable to noncontrolling interests	—	—	—	—	—
Total comprehensive income attributable to partners	$ 65	$ 65	$ 144	$ (209)	$ 65

Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (87)	$ 231	$ —	$ 144
INVESTING ACTIVITIES:					
Intercompany transfers	121	458	—	(579)	—
Capital expenditures	—	—	(48)	—	(48)
Investments in unconsolidated affiliates	—	—	(20)	—	(20)
Net cash provided by (used in) investing activities	121	458	(68)	(579)	(68)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(579)	579	—
Payments of long-term debt	—	(195)	—	—	(195)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	418	—	418
Distributions to limited partners and general partner	(121)	—	—	—	(121)
Distributions to noncontrolling interests	—	—	(2)	—	(2)
Other	—	(1)	—	—	(1)
Net cash (used in) provided by financing activities	(121)	(196)	(163)	579	99
Net change in cash and cash equivalents	—	175	—	—	175
Cash and cash equivalents, beginning of period	—	—	1	—	1
Cash and cash equivalents, end of period	$ —	$ 175	$ 1	$ —	$ 176

Condensed Consolidating Statements of Cash Flows
Three Months Ended March 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (92)	$ 243	$ —	$ 151
INVESTING ACTIVITIES:					
Intercompany transfers	121	103	—	(224)	—
Capital expenditures	—	—	(57)	—	(57)
Investments in unconsolidated affiliates	—	—	(12)	—	(12)
Change in restricted cash	—	(7)	—	—	(7)
Net cash provided by (used in) investing activities	121	96	(69)	(224)	(76)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(224)	224	—
Proceeds from long-term debt	—	892	—	—	892
Payments of long-term debt	—	(896)	—	—	(896)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	50	—	50
Distributions to limited partners and general partner	(121)	—	—	—	(121)
Distributions to noncontrolling interests	—	—	(2)	—	(2)
Net cash (used in) provided by financing activities	(121)	(4)	(176)	224	(77)
Net change in cash and cash equivalents	—	—	(2)	—	(2)
Cash and cash equivalents, beginning of period	—	—	3	—	3
Cash and cash equivalents, end of period	$ —	$ —	$ 1	$ —	$ 1

21. Subsequent Events

On April 25, 2017, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit. The distribution is payable on May 15, 2017 to unitholders of record on May 9, 2017.

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 Quarterly Report on Form 10-Q and the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2016.

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. Concurrent with the completion of the Transaction, as defined below, in the first quarter of 2017, management reevaluated our reportable segments and determined that our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Segment information for earlier periods has been restated to reflect these reportable segments. Our reportable segments include operating segments that have been aggregated based on the nature of the products and services provided. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering and selling condensate. Our Logistics and Marketing segment includes transporting, trading, marketing and storing natural gas and NGLs, fractionating NGLs and wholesale propane logistics. The remainder of our business operations is presented as "Other", and consists of unallocated corporate costs.

Our business is impacted by commodity prices and volumes. We mitigate a portion of commodity price risk on an overall Partnership basis by growing our fee based assets and by executing on our hedging program, where we hedge commodity prices associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing segment. Various factors impact both commodity prices and volumes, and as indicated in Item 3. "Quantitative and Qualitative Disclosures about Market Risk," we have sensitivities to certain cash and non-cash changes in commodity prices. If commodity prices weaken for a sustained period, our volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area; we will continue to target our strategy in geographic areas where we expect producer drilling activity.

Our long-term view is that commodity prices will be at levels we believe will support growth in natural gas, condensate and NGL production. We believe future commodity prices will be influenced by the severity of winter and summer weather, the level of North American production and drilling activity by exploration and production companies and the balance of trade between imports and exports of liquid natural gas, NGLs and crude oil.

NGL prices are impacted by the demand from petrochemical and refining industries and export facilities. The petrochemical industry has been making significant investment in building and expanding facilities to convert chemical plants from a heavier oil-based feedstock to lighter NGL-based feedstocks, including ethane. This increased demand expected in the next year should provide support for the increasing supply of ethane. Prior to those facilities commencing operations, ethane prices could remain weak with supply in excess of demand. In addition, export facilities are being expanded and built, which provide support for the increasing supply of NGLs. Although there can be, and has been, volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

Although we have seen a number of bankruptcies by producers in recent years, we believe our contract structure with our producers protects us from a credit perspective since we generally hold the product, sell it and withhold our fees prior to remittance of payments to the producer. Currently, our top 20 producers account for a majority of the total natural gas that we gather and process and of these top 20 producers, ten are investment grade while the remainder are not investment grade.

In addition to the U.S. financial markets, many businesses and investors continue to monitor global economic conditions. Uncertainty abroad may contribute to volatility in domestic financial and commodity markets.

We believe we are positioned to withstand current and future commodity price volatility as a result of the following:

- Our growing fee-based business represents a significant portion of our estimated margins.
- We have positive operating cash flow from our well-positioned and diversified assets.
- We have a well-defined and targeted hedging program.
- We prudently manage our capital expenditures with significant focus on fee-based growth projects.

- We believe we have a strong capital structure and balance sheet.
- We believe we have access to sufficient capital.

Increased activity levels in producing basins combined with access to capital markets at relatively low costs have historically enabled us to execute our growth strategy. Our targeted strategy may take numerous forms such as organic build opportunities within our footprint, joint venture opportunities, and acquisitions. Growth opportunities will be evaluated in cooperation with producers and customers based on the expected level of drilling activity in these geographic regions and the impacts of higher costs of capital.

Some of our growth projects include the following:

- Within our Logistics and Marketing segment, the Sand Hills pipeline mainline capacity expansion was placed into service during the second quarter of 2016. We are currently further expanding the Sand Hills pipeline to 365 MBbls/d expected to be in service in the fourth quarter of 2017, and have multiple additional Sand Hills lateral connections in flight throughout 2017.
- Within our Gathering and Processing segment, the construction of a 200 MMcf/d cryogenic natural gas processing plant, Mewbourn 3 plant, and further expansion of our Grand Parkway gathering system, both of which are located in the DJ Basin and expected to be in service in the fourth quarter of 2018.

Recent Events

On April 11, 2017, Kinder Morgan Texas Pipeline LLC, a subsidiary of Kinder Morgan, Inc., and DCP Midstream, LP announced they signed a non-binding letter of intent for the Partnership to participate in the development of the proposed Gulf Coast Express Pipeline Project, which will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. The project is designed to transport up to 1,700,000 dekatherms per day (Dth/d) of natural gas through approximately 430 miles of 42-inch pipeline from the Waha, Texas area to Agua Dulce, Texas. The pipeline is expected to be in service in the second half of 2019, subject to shipper commitments.

On December 30, 2016, the Partnership entered into a Contribution Agreement with DCP Midstream, LLC and DCP Midstream Operating, LP (the "Operating Partnership"). On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash. In consideration of the Partnership's receipt of the Contributions, (i) the Partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to DCP Midstream GP, LP, the General Partner, in a private placement and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC's debt. The transactions and documents contemplated by the Contribution Agreement are collectively referred to as the "Transaction".

We announced a quarterly distribution of $0.78 per unit for the first quarter of 2017. This distribution remains unchanged from the previous quarter and the first quarter of 2016.

Our Operating Segments

Gathering and Processing Segment

General

Our Gathering and Processing segment consists of a geographically diverse complement of assets and ownership interests that provide a varied array of wellhead to market services for our producer customers in Alabama, Colorado, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas and Wyoming. These services include gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering and selling condensate. Our Gathering and Processing segment's operations are organized into four regions: North, Permian, Midcontinent and South. Our geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas resource type or producing area. We believe our current geographic mix of assets is an important factor for maintaining and growing overall volumes and cash flow for this segment. Our assets are positioned in certain areas with active drilling programs and opportunities for organic growth.

We provide our producer customers with gathering and processing services that allow them to move their raw (unprocessed) natural gas to market. Raw natural gas is gathered, compressed and transported through pipelines to our processing facilities. In order for the raw natural gas to be accepted by the downstream market, we remove water, nitrogen and carbon dioxide and separate NGLs for further processing. Processed natural gas, usually referred to as residue natural gas, is then recompressed and delivered to natural gas pipelines and end users. The separated NGLs are in a mixed, unfractionated form and are sold and delivered through natural gas liquids pipelines to fractionation facilities for further separation.

We own or operate 61 natural gas processing plants and an interest in one additional plant through our 40% equity interest in Discovery Producer Services, LLC, or Discovery. At some of these facilities, we fractionate NGLs into individual components (ethane, propane, butane and natural gasoline).

We receive natural gas from a diverse group of producers under contracts with varying durations, and we receive fees or commodities from the producers to transport the natural gas from the wellhead to the processing plant. We receive fees or commodities as payment for our natural gas processing services, depending on the types of contracts we enter into with each supplier. We purchase or take custody of substantially all of our natural gas from producers, principally under fee-based percent-of-proceeds/index processing contracts.

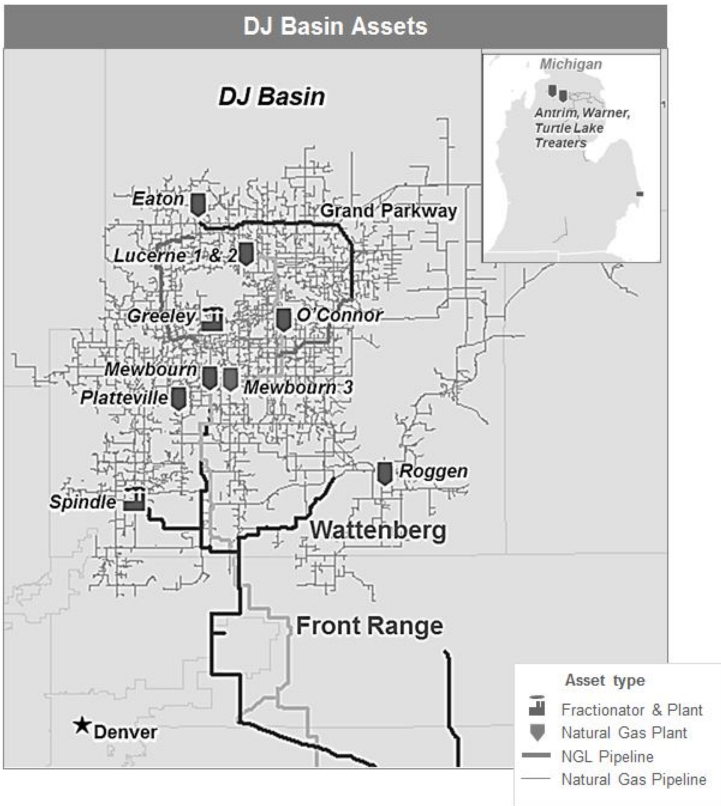
We actively seek new producing customers of natural gas on all of our systems to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been directly received or released from other gathering systems.

Our contracts with our producing customers in our Gathering and Processing segment are a mix of non-commodity sensitive fee-based contracts and commodity sensitive percent-of-proceeds and percent-of-liquids contracts. Percent-of-proceeds contracts are directly related to the price of natural gas, NGLs and condensate and percent-of-liquids contracts are directly related to the price of NGLs and condensate. Additionally, these contracts may include fee-based components. Generally, the initial term of these purchase agreements is three to five years and in some cases, the life of the lease. As we negotiate new agreements and renegotiate existing agreements, this may result in a change in contract mix period over period.

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. 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 to mitigate a portion of our commodity price exposure to NGLs.

Our systems each have significant customer acreage dedications that will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and also by contracting with undedicated producers who are operating in or around our gathering footprint.

North Region

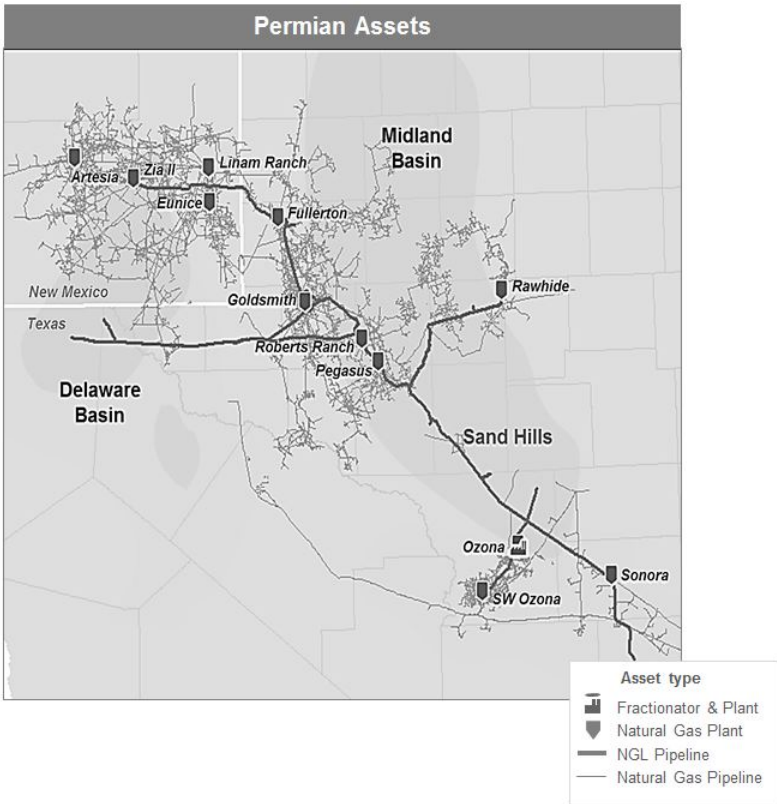


Our North region primarily consists of our DJ Basin system. We have a broad network of gathering and processing facilities in Weld County, Colorado that provide significant optionality and flexibility.

We are constructing a new 200 MMcf/d cryogenic natural gas processing plant, Mewbourn 3, which is projected to be in service by the end of 2018. Our Mewbourn 3 plant will increase capacity to support the growing processing needs of producers in the DJ Basin.

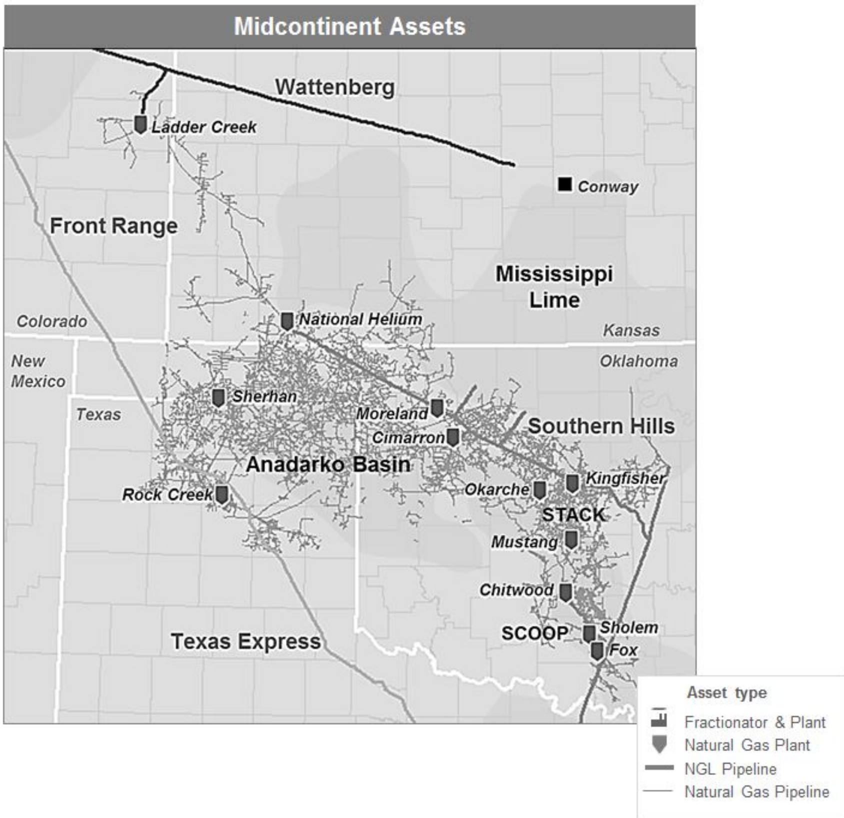
Our DJ Basin system delivers to the Mont Belvieu hub in Mont Belvieu, Texas via the Front Range and Texas Express pipelines, owned 33.33% and 10% by us, respectively, and to the Conway hub in Bushton, Kansas via our Wattenberg pipeline in our Logistics and Marketing segment.

Permian Region



Our Permian region primarily includes our West Texas system in the Midland Basin and our Southeast New Mexico system in the Delaware Basin. Producers continue to focus drilling activity on the most attractive acreage in the Midland and Delaware Basins. Our gathering and processing assets in the Permian region provide NGL takeaway service via our Sand Hills pipeline, owned 66.67% by us and 33.33% by Phillips 66, to fractionation facilities along the Gulf Coast and to Mont Belvieu hub.

Midcontinent Region

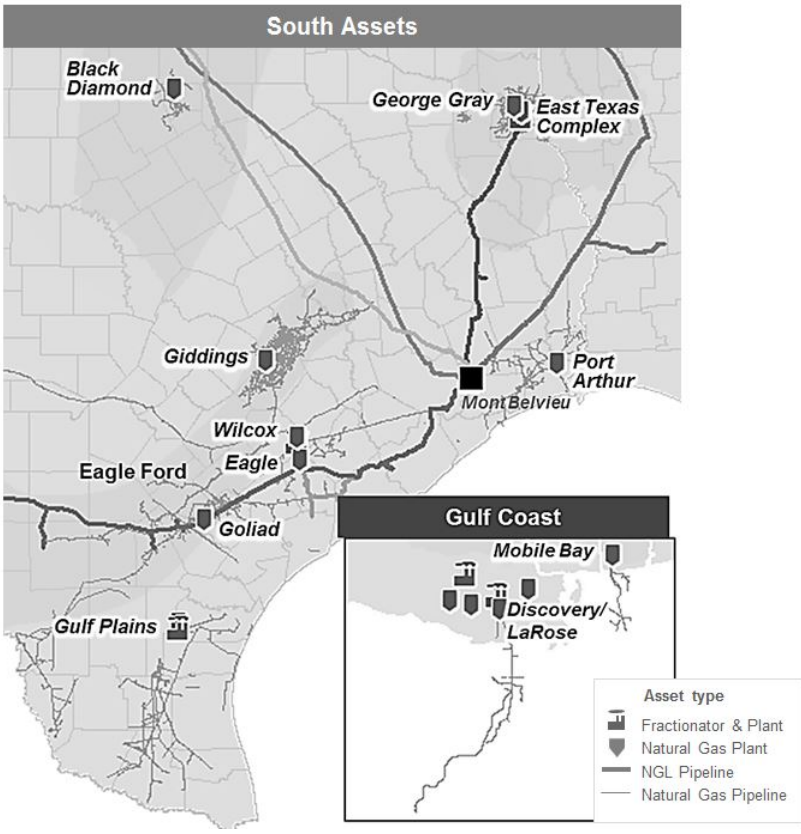


Our Midcontinent region primarily includes our Liberal system, Panhandle system, and our Central Oklahoma system. We gather and process raw natural gas primarily from the Ardmore and Anadarko Basins, including the prolific South Central Oklahoma Oil Province (“SCOOP”) play and the Sooner Trend Anadarko Basin Canadian and Kingfisher (“STACK”) play.

Existing production in the western Midcontinent region, which includes our Liberal and Panhandle systems, is typically from mature fields with shallow decline profiles that will provide our plants with a dependable source of raw natural gas over a long term. Our gathering system footprint in the eastern Midcontinent region, which includes our Central Oklahoma system, serves the SCOOP and STACK plays. The infrastructure of our plants and gathering facilities is uniquely positioned to pursue our consolidation strategy in this region.

Our gathering and processing assets in the Midcontinent region deliver NGLs to the Gulf Coast and Mont Belvieu via our Southern Hills pipeline, owned 66.67% by us and 33.33% by Phillips 66.

South Region



Our South region primarily includes our Eagle Ford system, East Texas system, and 40% interest in the Discovery system. The South region also included our Northern Louisiana system which was sold on July 1, 2016. We are pursuing cost efficiencies and increasing the utilization of our existing assets as overall drilling and production has declined in certain areas of the region.

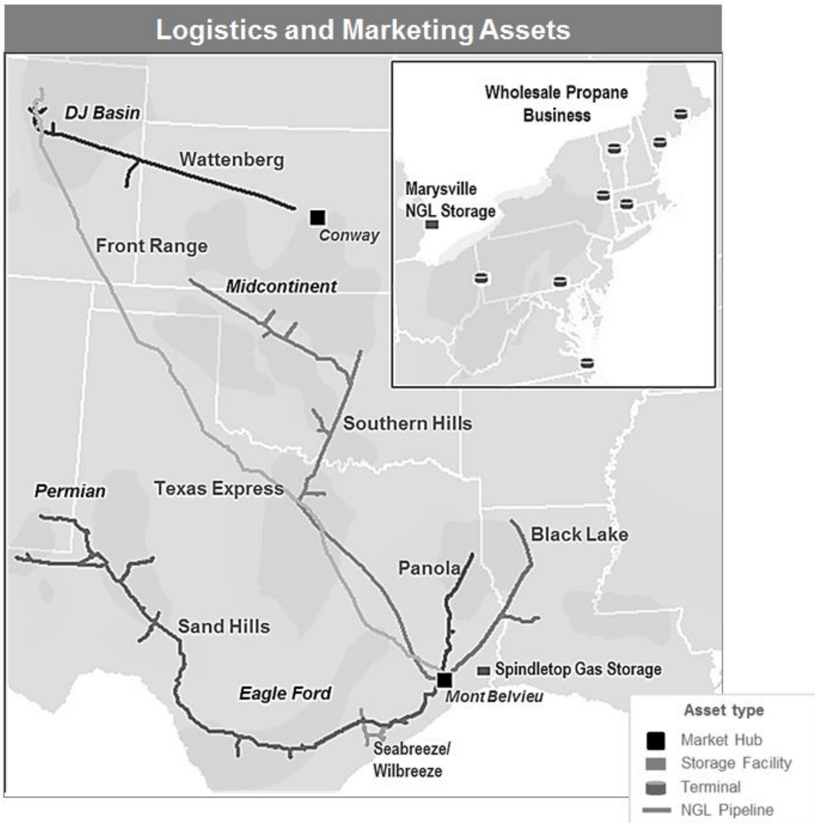
Our Eagle Ford system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through our Sand Hills pipeline and other third party NGL pipelines. Our East Texas system provides NGL takeaway service through the Panola pipeline, owned 15% by us, and delivers gas primarily through its Carthage Hub which delivers residue gas to multiple interstate and intrastate pipelines.

The Discovery system is operated by Williams Partners L.P., who owns a 60% interest, and offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Louisiana, and have access to downstream pipelines and markets.

Competition

We face strong competition in acquiring raw natural gas supplies. Our competitors in obtaining additional gas supplies and in gathering and processing raw natural gas includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Logistics and Marketing Segment



General

We market our NGLs and residue gas and provide logistics and marketing services to third-party NGL producers and sales customers in significant NGL production and market centers in the United States. This includes purchasing NGLs on behalf of third-party NGL producers for shipment on our NGL pipelines and resale in key markets.

Our NGL services include plant tailgate purchases, transportation, fractionation, flexible pricing options, price risk management and product-in-kind agreements. Our primary NGL operations are located in close proximity to our Gathering and Processing assets in each of the operating regions.

Our NGL pipelines transport NGLs from natural gas processing plants to fractionation facilities, a petrochemical plant and a third party underground NGL storage facility. Our pipelines provide transportation services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to recover NGLs from natural gas because of the higher value of natural gas compared to the value of NGLs. As a result, we have experienced periods, and will likely experience periods in the future, when higher relative natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

Our natural gas systems have the ability to deliver gas into numerous downstream transportation pipelines and markets. Many of our outlets transport gas to premium markets in the eastern United States, further enhancing the competitiveness of our commercial efforts in and around our natural gas gathering systems. We sell residue gas on behalf of our producer customers and residue gas which we earn under our gas supply agreements, supplying the residue gas demands of end-use customers physically attached to our pipeline systems and managing excess capacity of our owned storage and transportation assets. End-users include large industrial companies, natural gas distribution companies and electric utilities. We are focused on extracting the highest possible value for the residue gas that results from our processing and transportation operations. We sell the residue gas at market-based prices.

Our ownership in various intrastate natural gas pipelines give us access to market centers/hubs such as Waha, Texas; Katy, Texas and the Houston Ship Channel and are used in our natural gas asset based trading activities.

NGL Pipelines

DCP Sand Hills Pipeline, LLC, or the Sand Hills pipeline, an interstate NGL pipeline in which we own a 66.67% interest, is a common carrier pipeline which provides takeaway service from plants in the Permian and the Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and at the Mont Belvieu, Texas market hub. We are currently further expanding the Sand Hills pipeline to 365 MBbls/d expected to be in service in the fourth quarter of 2017, and have multiple additional Sand Hills lateral connections in flight throughout 2017.

DCP Southern Hills Pipeline, LLC, or the Southern Hills pipeline, an interstate NGL pipeline in which we owned a 66.67% interest, provides takeaway service from the Midcontinent to fractionation facilities at the Mont Belvieu, Texas market hub.

Front Range Pipeline LLC, or the Front Range pipeline, an interstate NGL pipeline in which we own a 33.33% interest, originates in the DJ Basin and extends to Skellytown, Texas. The Front Range pipeline connects to our O'Connor, Lucerne 1, Lucerne 2, and Mewbourn plants as well as third party plants in the DJ Basin. Enterprise is the operator of the pipeline.

Texas Express Pipeline LLC, or the Texas Express pipeline, an intrastate NGL pipeline in which we own a 10% interest, originates near Skellytown in Carson County, Texas, and extends to Enterprise Products Partners L.P.'s, or Enterprise, natural gas liquids fractionation and storage complex at Mont Belvieu, Texas. The pipeline also provides access to other third party facilities in the area. Enterprise is the operator of the pipeline.

The Southern Hills, Sand Hills, Texas Express, and Front Range pipelines have in place long-term, fee-based transportation agreements, a portion of which are ship-or-pay, with us as well as third party shippers. These NGL pipelines collect fee-based transportation revenue under regulated tariffs.

NGL Fractionation Facilities

We own a 12.5% interest in the Enterprise fractionator operated by Enterprise and a 20% interest in the Mont Belvieu 1 fractionator operated by ONEOK Partners, both located in Mont Belvieu, Texas. The fractionation facilities separate NGLs received from processing plants into their individual components. These fractionation services are provided on a fee basis. The results of operations for this business are generally dependent upon the volume of NGLs fractionated and the level of fees charged to customers.

Storage Facilities

Our NGL storage facility, which stores ethane, propane and butane, is located in Marysville, Michigan and has strategic access to the Marcellus, Utica and Canadian NGLs. Our facility includes 11 underground salt caverns with approximately 8 MMBbls of storage capacity. Our facility serves regional refining and petrochemical demand, and helps to balance the seasonality of propane distribution in the Midwestern and Northeastern United States and in Sarnia, Canada. We provide services to customers primarily on a fee basis under multi-year storage agreements. The results of operations for this business are generally dependent upon the volume stored and the level of fees charged to customers.

Our Spindletop natural gas storage facility is located in Texas and plays an important role in our ability to act as a full-service natural gas marketer. The facility has capacity for residue gas of approximately 12 Bcf. We may lease a portion of the facility’s capacity to third-party customers, and use the balance to manage relatively constant natural gas supply volumes with uneven demand levels, provide “backup” service to our customers and support our asset based trading activities. Our asset based trading activities are designed to realize margins related to fluctuations in commodity prices, time spreads and basis differentials and to maximize the value of our storage facility.

Wholesale Propane

We operate a wholesale propane logistics business in the mid-Atlantic, upper Midwest and Northeastern United States. We purchase large volumes of propane supply from fractionation facilities and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities. We primarily sell propane on a wholesale basis to propane distributors under annual sales agreements who in turn resell propane to their customers. Our operations include one owned marine terminal, one owned propane pipeline terminal and six owned propane rail terminals, with a combined capacity of approximately 550 MBbls, and access to several open access pipeline terminals.

The wholesale propane marketing business is significantly impacted by seasonal and weather-driven demand, particularly in the winter, which can impact the price and volume of propane sold in the markets we serve.

Trading and Marketing

Our energy trading operations are exposed to market variables and commodity price risk. We manage commodity price risk related to our natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. We may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments 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.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. 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. 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.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas. 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. As discussed above, the accounting for physical gas purchases and sales and the accounting for the derivative instruments used to manage such purchases and sales differ, and may subject our earnings to market volatility, even though the transaction represents an economic hedge in which we have locked in a future margin.

We sell NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small regional retail propane distributors.

Competition

The Logistics and Marketing business is highly competitive in our markets and includes interstate and intrastate pipelines, integrated oil and gas companies that produce, fractionate, transport, store and sell natural gas and NGLs, and underground storage facilities. Competition is often the greatest in geographic areas experiencing robust drilling by producers and strong petrochemical demand and during periods of high NGL prices relative to natural gas. Competition is also increased in those geographic areas where our contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Competition in the NGLs marketing area comes from other midstream NGL marketing companies, international producers/traders, chemical companies, refineries and other asset owners. Along with numerous marketing competitors, we offer price risk management and other services. We believe it is important that we tailor our services to the end-use customer to remain competitive.

General Trends and Outlook

During 2017, our strategic objectives will continue to focus on maintaining stable Distributable Cash Flows from our existing assets and executing on opportunities to sustain our long-term Distributable Cash Flows in light of the significant changes to our business resulting from the Transaction. 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 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. Our 2017 plan includes maintenance capital expenditures of between $100 million and $145 million, and expansion capital expenditures between $325 million and $375 million associated with approved projects, for the year ending December 31, 2017. Expansion capital expenditures include the construction of the Mewbourn 3 plant and Grand Parkway Phase 2 in our DJ Basin system, and the capacity expansion of the Sand Hills pipeline, which is shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows.

For an in-depth discussion of factors that may significantly affect our results, see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Factors That May Significantly Affect Our Results” included in our Annual Report on Form 10-K for the year ended December 31, 2016.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our condensed consolidated results of operations for the three months ended March 31, 2017 and 2016. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three Months Ended March 31,		Variance 2017 vs. 2016	
	2017	2016	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues (a):				
Gathering and Processing	$ 1,359	$ 936	$ 423	45 %
Logistics and Marketing	1,927	1,264	663	52 %
Inter-segment eliminations	(1,165)	(736)	429	58 %
Total operating revenues	2,121	1,464	657	45 %
Purchases of natural gas and NGLs				
Gathering and Processing	(983)	(667)	316	47 %
Logistics and Marketing	(1,869)	(1,204)	665	55 %
Inter-segment eliminations	1,165	736	429	58 %
Total purchases	(1,687)	(1,135)	552	49 %
Operating and maintenance expense	(167)	(179)	(12)	(7)%
Depreciation and amortization expense	(94)	(95)	(1)	(1)%
General and administrative expense	(62)	(62)	—	— %
Other (expense) income	(10)	87	(97)	*
Interest expense	(73)	(79)	(6)	(8)%
Earnings from unconsolidated affiliates (b)	74	66	8	12 %
Income tax expense	(1)	(2)	(1)	(50)%
Net income attributable to partners	$ 101	$ 65	$ 36	55 %
Other data:				
Gross margin (c):				
Gathering and Processing	$ 376	$ 269	$ 107	40 %
Logistics and Marketing	58	60	$ (2)	(3)%
Total gross margin	$ 434	$ 329	$ 105	32 %
Non-cash commodity derivative mark-to-market	$ 36	$ (45)	$ 81	*
Natural gas wellhead (MMcf/d) (d)	4,580	5,431	(851)	(16)%
NGL gross production (MBbls/d) (d)	352	396	(44)	(11)%
NGL pipelines throughput (MBbls/d) (d)	427	399	28	7 %

* Percentage change is not meaningful.

(a) Operating revenues include the impact of trading and marketing gains, net.
(b) 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.
(c) Gross margin consists of total operating revenues, including trading and marketing gains and losses, less purchases of natural gas and NGLs. Segment gross margin for each segment consists of total operating revenues for that segment, including trading and marketing gains, net, less purchases of natural gas and NGLs for that segment. Please read “Reconciliation of Non-GAAP Measures”.
(d) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and throughput volumes and NGL production.

Three months ended March 31, 2017 vs. Three months ended March 31, 2016

Total Operating Revenues — Total operating revenues increased $657 million in 2017 compared to 2016 primarily as a result of the following:

- $423 million increase for our Gathering and Processing segment primarily due to higher commodity prices, higher gas and NGL sales volumes primarily related to our North region which impact both sales and purchases, favorable commodity derivative activity, partially offset by lower gas and NGL sales volumes in the South, Midcontinent and Permian regions; and
- $663 million increase for our Logistics and Marketing segment primarily due to increased commodity prices, increased propane volumes, partially offset by lower gas and NGL sales volumes and unfavorable commodity derivative activity;

These increases were partially offset by:

- $429 million increase in inter-segment eliminations, which relate to sales of NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices, partially offset by lower gas and NGL sales volumes.

Total Purchases — Total purchases increased $552 million in 2017 compared to 2016 primarily as a result of the following:

- $316 million increase for our Gathering and Processing segment for the reasons discussed above; and
- $665 million increase for our Logistics and Marketing segment for the reasons discussed above;

These increases were partially offset by:

- $429 million increase in inter-segment eliminations, which relate to sales of NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices, partially offset by lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2017 compared to 2016 primarily as a result of our headcount reduction in April of 2016, other cost savings initiatives and the sale of our Northern Louisiana system in July 2016.

Other (Expense) Income — Other income in 2016 represents a producer settlement net of legal fees.

Interest Expense - Interest expense decreased in 2017 compared to 2016 as a result of lower average outstanding debt balances.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily as a result of higher treating fees, higher commodity prices and lower operating expenses at Discovery in our Gathering and Processing segment and the expansion and volume ramp up of the Sand Hills NGL pipeline in our Logistics and Marketing segment.

Net Income Attributable to Partners — Net income attributable to partners increased in 2017 compared to 2016 for the reasons discussed above.

Gross Margin — Gross margin increased $105 million in 2017 compared to 2016 primarily as a result of the following:

- $107 million increase for our Gathering and Processing segment primarily related to higher commodity prices, favorable commodity derivative activity, higher margins on a specific producer arrangement, higher NGL recoveries and a producer settlement in our North region, and contract realignment efforts in our Permian and Midcontinent regions. This increase was partially offset by lower volumes across our South, Midcontinent, and Permian regions due to reduced drilling activity in prior periods and the sale of our Northern Louisiana system;

  These increases were partially offset by:

- $2 million decrease for our Logistics and Marketing segment primarily related to unfavorable commodity derivative activity, partially offset by favorable NGL marketing activity and higher storage margins.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended March 31,	
	2017	2016
	(Millions)	
DCP Sand Hills Pipeline, LLC	$ 31	$ 25
Discovery Producer Services LLC	20	15
DCP Southern Hills Pipeline, LLC	11	12
Front Range Pipeline LLC	4	5
Texas Express Pipeline LLC	2	2
Mont Belvieu Enterprise Fractionator	3	4
Mont Belvieu 1 Fractionator	1	3
Other	2	—
Total earnings from unconsolidated affiliates	$ 74	$ 66

Distributions received from investments in unconsolidated affiliates were as follows:

	Three Months Ended March 31,	
	2017	2016
	(Millions)	
DCP Sand Hills Pipeline, LLC	$ 27	$ 32
Discovery Producer Services LLC	25	23
DCP Southern Hills Pipeline, LLC	12	15
Front Range Pipeline LLC	2	5
Texas Express Pipeline LLC	3	3
Mont Belvieu Enterprise Fractionator	4	6
Mont Belvieu 1 Fractionator	1	3
Other	2	—
Total distributions from unconsolidated affiliates	$ 76	$ 87

Results of Operations — Gathering and Processing Segment

Operating Data

Regions	Plants	Approximate Gathering and Transmission Systems (Miles)	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Three Months Ended March 31, 2017 Natural Gas Wellhead Volume (MMcf/d) (a)	NGL Production (MBbls/d) (a)
North	13	5,440	1,255	1,141	86
Permian	16	16,300	1,460	961	98
Midcontinent	12	29,210	1,765	1,199	88
South	20	8,715	3,210	1,279	80
Total	61	59,665	7,690	4,580	352

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.

The results of operations for our Gathering and Processing segment are as follows:

	Three Months Ended March 31,		Variance 2017 vs. 2016	
	2017	2016	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 1,197	$ 796	$ 401	50 %
Transportation, processing and other	140	135	5	4 %
Trading and marketing gains, net	22	5	17	*
Total operating revenues	1,359	936	423	45 %
Purchases of natural gas and NGLs	(983)	(667)	316	47 %
Operating and maintenance expense	(153)	(161)	(8)	(5)%
Depreciation and amortization expense	(85)	(86)	(1)	(1)%
General and administrative expense	(6)	(4)	2	50 %
Other income	—	87	87	*
Earnings from unconsolidated affiliates (a)	20	15	5	33 %
Segment net income	152	120	32	27 %
Segment net income attributable to noncontrolling interests	—	—	—	— %
Segment net income attributable to partners	$ 152	$ 120	$ 32	27 %
Other data:				
Segment gross margin (b)	$ 376	$ 269	$ 107	40 %
Non-cash commodity derivative mark-to-market	$ 31	$ (39)	$ 70	*
Natural gas wellhead (MMcf/d) (c)	4,580	5,431	(851)	(16)%
NGL gross production (MBbls/d) (c)	352	396	(44)	(11)%

* Percentage change is not meaningful.

(a) For entities not wholly-owned by us, 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.

(b) Segment gross margin consists of total operating revenues, including trading and marketing gains, net, less purchases of natural gas and NGLs. Please read “Reconciliation of Non-GAAP Measures”.

(c) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and throughput volumes and NGL production.

Three Months Ended March 31, 2017 vs. Three Months Ended March 31, 2016

Total Operating Revenues — Total operating revenues increased $423 million in 2017 compared to 2016, primarily as a result of the following:

- $523 million increase attributable to higher commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $17 million increase attributable to higher gas and NGL sales volumes and the impact of a specific producer arrangement primarily related to our DJ Basin system in our North region;
- $5 million increase in transportation, processing and other primarily related to fee based contract realignment efforts, partially offset by lower volumes in the South region and the sale of our Northern Louisiana System;
- $17 million increase as a result of commodity derivative activity attributable to a $53 million decrease in realized cash settlement gains in 2017, partially offset by an decrease in unrealized commodity derivative losses of $70 million due to movements in forward prices of commodities;

These increases were partially offset by:

- $139 million decrease primarily as a result of lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $316 million in 2017 compared to 2016 as a result of higher commodity prices and higher gas and NGL sales volumes in our North region, partially offset by decreased volumes in our South, Midcontinent and Permian regions.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2017 compared to 2016 primarily as a result of our headcount reduction in April of 2016, other cost savings initiatives and the sale of our Northern Louisiana system in July 2016.

Other Income — Other income in 2016 represents a producer settlement net of legal fees.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily as a result of higher treating fees, higher commodity prices and lower operating expenses at Discovery.

Segment Gross Margin — Segment gross margin increased $107 million in 2017 compared to 2016, primarily as a result of the following:

- $99 million increase as a result of higher commodity prices;
- $19 million increase as a result of higher margins on a specific producer arrangement and higher NGL recoveries primarily related to our DJ Basin system and a producer settlement in our North region;
- $17 million increase as a result of commodity derivative activity as discussed above;

These increases were partially offset by:

- $24 million decrease primarily as a result of lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods, partially offset by fee based contract realignment efforts in the Permian and Midcontinent region;
- $4 million decrease as a result of the sale of our Northern Louisiana system in our South region.

Total Wellhead Volumes — Natural gas wellhead decreased in 2017 compared to 2016 reflecting lower volumes primarily from (i) our Eagle Ford and East Texas systems within our South region and (ii) lower volumes associated with general declines within the Permian and Midcontinent regions and (iii) the sale of our Northern Louisiana system within our South region.

NGL Gross Production — NGL production decreased in 2017 compared to 2016 primarily as a result from (i) our Eagle Ford and East Texas systems within our South region and (ii) lower volumes associated with general declines within the Permian and Midcontinent regions and (iii) the sale of our Northern Louisiana system within our South region.

Results of Operations — Logistics and Marketing Segment

Operating Data

				Three Months Ended March 31, 2017	
System	**Approximate System Length (Miles)**	**Fractionators**	**Approximate Throughput Capacity (MBbls/d) (a)**	**Pipeline Throughput (MBbls/d) (a)**	**Fractionator Throughput (MBbls/d) (a)**
Sand Hills pipeline	1,350	—	186	169	—
Southern Hills pipeline	940	—	117	67	—
Front Range pipeline	450	—	50	34	—
Texas Express pipeline	595	—	28	14	—
Other pipelines	1,180	—	172	143	—
Mont Belvieu fractionators	—	2	60	—	42
Total	4,515	2	613	427	42

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.

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

	Three Months Ended March 31,		Variance 2017 vs. 2016	
	2017	2016	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues:				
Sales of natural gas and NGLs	$ 1,901	$ 1,233	$ 668	54 %
Transportation, processing and other	17	18	(1)	(6)%
Trading and marketing gains, net	9	13	(4)	(31)%
Total operating revenues	1,927	1,264	663	52 %
Purchases of natural gas and NGLs	(1,869)	(1,204)	665	55 %
Operating and maintenance expense	(9)	(10)	(1)	(10)%
Depreciation and amortization expense	(4)	(4)	—	— %
General and administrative expense	(3)	(3)	—	— %
Other expense	(9)	—	9	*
Earnings from unconsolidated affiliates (a)	54	51	3	6 %
Segment net income attributable to partners	$ 87	$ 94	$ (7)	(7)%
Other data:				
Segment gross margin	$ 58	$ 60	$ (2)	(3)%
Non-cash commodity derivative mark-to-market	$ 5	$ (6)	11	*
NGL pipelines throughput (MBbls/d) (a)	427	399	28	7 %

(a) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the throughput volumes of unconsolidated affiliates. 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.

Three Months Ended March 31, 2017 vs. Three Months Ended March 31, 2016

Total Operating Revenues — Total operating revenues increased $663 million in 2017 compared to 2016, primarily as a result of the following:

- $778 million increase as a result of higher commodity prices, which impacted both sales and purchases, before the impact of derivative activity;

  These increases were partially offset by:

- $92 million decrease attributable to lower gas and NGL sales volumes, which impacted both sales and purchases;
- $4 million decrease as a result of commodity derivative activity attributable to a $15 million decrease in realized cash settlement gains in 2017, partially offset by an decrease in unrealized commodity derivative losses of $11 million due to movements in forward prices of commodities;
- $19 million decrease due to the sale of our Northern Louisiana system.

Purchases of NGLs — Purchases of NGLs increased $665 million in 2017 compared to 2016, primarily as a result of higher commodity prices, partially offset by lower gas and NGL sales volumes.

Other expense — Other expense in 2017 represents the write-off of property, plant and equipment associated with the expiration of a lease.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily as a result of higher throughput volumes on Sand Hills due to the capacity expansion in the second quarter of 2016.

Segment Gross Margin — Segment gross margin decreased $2 million in 2017 compared to 2016, primarily as a result of the following:

- $4 million decrease as a result of commodity derivative activity as discussed above.

  These decreases were partially offset by:

- $2 million increase primarily due to higher NGL storage margins.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2017 compared to 2016 primarily as a result of higher throughput volumes on Sand Hills due to the capacity expansion in the second quarter of 2016.

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 Credit Agreement;
- debt offerings;
- issuances of additional common units;
- borrowings under term loans; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- quarterly distributions to our unitholders and General Partner;
- payments to service our debt;
- growth capital expenditures;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions; and
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements.

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.

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, further impact our credit ratings, raise our financing costs, as well as impact our compliance with our financial covenant requirements under the Credit Agreement and the indentures governing our notes.

In February 2017, we further amended our $1.25 billion senior unsecured revolving credit agreement that matures on May 1, 2019, or the Credit Agreement, to increase the aggregate commitments under the unsecured revolving credit facility to approximately $1.4 billion. The Credit Agreement is used for working capital requirements and other general partnership purposes including acquisitions.

As of March 31, 2017, there were no outstanding borrowings on the revolving credit facility under the Credit Agreement. We had unused borrowing capacity of $1,374 million, net of $24 million of letters of credit, under the Credit Agreement. The financial covenants set forth in the Credit Agreement limit the Partnership's ability to incur incremental debt by $1,106 million as of March 31, 2017. Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. In the first quarter of 2017, our credit rating was lowered. As a result of this action, interest rates on outstanding borrowings under the Credit Agreement increased. As of May 5, 2017, we had no outstanding borrowings on the revolving credit facility and had approximately $1,374 million, net of $24 million of letters of credit, of unused borrowing capacity under the Credit Agreement. We used a portion of the cash received from the Transaction to repay outstanding debt on our revolving credit facility.

On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash. In consideration of the Partnership's receipt of the Contributions, (i) the Partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to DCP Midstream GP, LP, the General Partner, in a private placement, and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC's debt. The incentive distributions payable to the holders of the Partnership's incentive distribution rights with respect to the fiscal years 2017, 2018 and 2019, in certain circumstances, may be reduced in an amount up to $100 million per fiscal year as necessary to provide that the Distributable Cash Flow of the Partnership (as adjusted) during such year meets or exceeds the amount of distributions made by the Partnership (as adjusted) to the partners of the partnership with respect to such year.

In April 2015, we filed a shelf registration statement with the SEC, that became effective upon filing, which allows us to issue an unlimited amount of common units and debt securities. We have issued no common units or debt securities under this registration statement.

We also have a shelf registration statement that was declared effective in July 2014 allowing us to issue up to $500 million in common units pursuant to our 2014 equity distribution agreement. During the three months ended March 31, 2017, we issued no common units and approximately $349 million of common units remained available for sale pursuant to our 2014 equity distribution agreement.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through the first quarter of 2018 with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 3. "Quantitative and Qualitative Disclosures about Market Risk" contained herein.

When we enter into commodity swap 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.

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, cash collateral we may be required to post with counterparties to our commodity derivative instruments, borrowings of and payments on debt, capital expenditures, and increases or decreases in other long-term assets.

We had working capital deficits of $410 million and $629 million as of March 31, 2017 and December 31, 2016, respectively. The change in working capital is primarily attributable to the cash received in the Transaction offset by the repayment of long-term debt outstanding on the revolving credit facility. We had a net derivative working capital deficit of $5 million as of March 31, 2017 as compared to net derivative working capital deficit of $49 million as of December 31, 2016. We expect that our future working capital requirements will be impacted by these same recurring factors.

As of March 31, 2017, we had $176 million in cash and cash equivalents, of which $1 million was held by consolidated subsidiaries we did not wholly own.

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

	Three Months Ended March 31,	
	2017	2016
	(Millions)	
Net cash provided by operating activities	$ 144	$ 151
Net cash used in investing activities	$ (68)	$ (76)
Net cash provided by (used in) financing activities	$ 99	$ (77)

Three Months Ended March 31, 2017 vs. Three Months Ended March 31, 2016

Operating Activities — The changes in net cash provided by operating activities are attributable to our net income (loss) adjusted for non-cash charges and changes in working capital as presented in the condensed consolidated statements of cash flows.

We received cash distributions from unconsolidated affiliates of $76 million and $87 million during the three months ended March 31, 2017 and 2016, respectively. For the three months ended March 31, 2017 and 2016, cash distributions from unconsolidated affiliates exceeded earnings from unconsolidated affiliates by $2 million and $21 million, respectively. For additional information regarding fluctuations in our earnings from unconsolidated affiliates, please read "Results of Operations".

Investing Activities — Net cash used in investing activities during the three months ended March 31, 2017 was comprised of: (1) capital expenditures of $48 million, primarily for (1) expansion capital expenditures including construction of the Mewbourn 3 plant, and (2) investment in unconsolidated affiliates, net of $20 million for the capacity expansion of the Sand Hills pipeline.

Net cash used in investing activities during the three months ended March 31, 2016 was comprised of: (1) capital expenditures of $57 million, which generally consisted of maintenance capital expenditures for our existing facilities and expansion capital expenditures for construction of additional gathering systems, processing plants, fractionators and other facilities and infrastructure and well connections; (2) investment in unconsolidated affiliates, net of $12 million and (3) restricted cash of $7 million.

Financing Activities — Net cash provided by financing activities increased $176 million in 2017 compared to the same period in 2016 primarily as a result of the following:

Net cash provided by financing activities during the three months ended March 31, 2017 was comprised of: (1) cash received from the Transaction of $418 million, (2) payment of debt outstanding on the revolving credit facility of $195 million from cash received from the Transaction and (3) distributions paid to limited partners and the general partner of $121 million.

Net cash used in financing activities during the three months ended March 31, 2016 was comprised of: (1) payment of long-term debt of $896 million and (2) distributions paid to limited partners and the general partner of $121 million; which were partially offset by (3) proceeds from long-term debt of $892 million, net of issuance costs, and (4) $50 million attributable to the net change in advances to our predecessor operations from DCP Midstream, LLC as a result of the Transaction.

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 $100 million and $145 million, and approved expansion capital expenditures of between $325 million and $375 million, for the year ending December 31, 2017. Expansion capital expenditures include the construction of the Mewbourn 3 plant and Grand Parkway Phase 2 in our DJ Basin system, and the capacity expansion of the Sand Hills pipeline, which is shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows.

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

	Three Months Ended March 31, 2017			Three Months Ended March 31, 2016		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 15	$ 35	$ 50	$ 28	$ 26	$ 54
Noncontrolling interest portion and reimbursable projects (a)	2	(4)	(2)	3	—	3
Total	$ 17	$ 31	$ 48	$ 31	$ 26	$ 57

(a) Represents the noncontrolling interest and reimbursable portion of our capital expenditures. We have entered into agreements with third parties whereby we will be reimbursed for certain expenditures. Depending on the timing of these payments, we may be reimbursed prior to incurring the capital expenditure.

In addition, we invested cash in unconsolidated affiliates of $20 million and $12 million during the three months ended March 31, 2017 and 2016, 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, to fund future acquisitions and capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, the issuance of additional partnership units and the issuance of long-term debt.

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 $121 million and $121 million during the three months ended March 31, 2017 and 2016, 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.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 12. "Partnership Equity and Distributions" in the Notes to Condensed Consolidated Financial Statements in Item 8. “Financial Statements.”

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of March 31, 2017, was as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(Millions)				
Debt (a)	$ 8,475	$ 786	$ 1,874	$ 866	$ 4,949
Operating lease obligations	209	55	70	46	38
Purchase obligations (b)	2,823	562	829	659	773
Other long-term liabilities (c)	144	—	10	7	127
Total	$ 11,651	$ 1,403	$ 2,783	$ 1,578	$ 5,887

(a) Includes interest payments on debt securities that have been issued. These interest payments are $286 million, $499 million, $366 million, and $2,099 million for less than one year, one to three years, three to five years, and thereafter, respectively.

(b) Our purchase obligations are contractual obligations and include purchase orders and non-cancelable construction agreements for capital expenditures, various non-cancelable commitments to purchase physical quantities of commodities in future periods and other items, including long-term fractionation agreements. For contracts where the price paid is based on an index or other market-based rates, the amount is based on the forward market prices or current market rates as of March 31, 2017. Purchase obligations exclude accounts payable, accrued taxes 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 sheets, 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.

(c) Other long-term liabilities include asset retirement obligations, long-term environmental remediation liabilities, gas purchase liabilities, right of way liabilities and other miscellaneous liabilities recognized in the March 31, 2017 condensed consolidated balance sheet. The table above excludes non-cash obligations as well as $28 million of deferred state income taxes, $28 million of Executive Deferred Compensation Plan contributions and $6 million of long-term incentive plans as the amount and timing of any payments are not subject to reasonable estimation.

Off-Balance Sheet Obligations

As of March 31, 2017, we had no items that were classified as off-balance sheet obligations.

Reconciliation of Non-GAAP Measures

Gross Margin and Segment Gross Margin — In addition to net income, 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, less purchases of natural gas and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. 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 adjusted for (i) distributions from unconsolidated affiliates, net of earnings (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations. Management believes these measures provide investors meaningful insight into results from ongoing operations.

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 adjusted for (i) distributions from unconsolidated affiliates, net of earnings (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted segment EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations 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.

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 accompanying schedules provide reconciliations of gross margin, segment gross margin and adjusted segment EBITDA to their most directly comparable GAAP financial measures.

Distributable Cash Flow — We define Distributable Cash Flow as adjusted EBITDA, as defined above, less maintenance capital expenditures, net of reimbursable projects, less interest expense and certain other items. 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. We compare the Distributable Cash Flow we generate to the cash distributions we expect to pay our partners. Using this metric, we compute our distribution coverage ratio. 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.

The following table sets forth our reconciliation of certain non-GAAP measures:

	Three Months Ended March 31,	
	2017	2016
Reconciliation of Non-GAAP Measures	(Millions)	
Reconciliation of net income attributable to partners to gross margin:		
Net income attributable to partners	$ 101	$ 65
Interest expense	73	79
Income tax expense	1	2
Operating and maintenance expense	167	179
Depreciation and amortization expense	94	95
General and administrative expense	62	62
Other expense (income)	10	(87)
Earnings from unconsolidated affiliates	(74)	(66)
Gross margin	$ 434	$ 329
Non-cash commodity derivative mark-to-market (a)	$ 36	$ (45)
Reconciliation of segment net income attributable to partners to segment gross margin:		
Gathering and Processing segment:		
Segment net income attributable to partners	$ 152	$ 120
Operating and maintenance expense	153	161
Depreciation and amortization expense	85	86
Other income	—	(87)
General and administrative expense	6	4
Earnings from unconsolidated affiliates	(20)	(15)
Segment gross margin	$ 376	$ 269
Non-cash commodity derivative mark-to-market (a)	$ 31	$ (39)
Logistics and Marketing segment:		
Segment net income attributable to partners	$ 87	$ 94
Operating and maintenance expense	9	10
Depreciation and amortization expense	4	4
Other expense	9	—
General and administrative expense	3	3
Earnings from unconsolidated affiliates	(54)	(51)
Segment gross margin	$ 58	$ 60
Non-cash commodity derivative mark-to-market (a)	$ 5	$ (6)

(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 March 31,	
	2017	2016
	(Millions)	
Reconciliation of net income attributable to partners to adjusted segment EBITDA:		
Gathering and Processing segment:		
Segment net income attributable to partners (a)	$ 152	$ 120
Non-cash commodity derivative mark-to-market	(31)	39
Depreciation and amortization expense	85	86
Distributions from unconsolidated affiliates, net of earnings	5	8
Adjusted segment EBITDA	$ 211	$ 253
Logistics and Marketing segment:		
Segment net income attributable to partners	$ 87	$ 94
Noncash commodity derivative mark-to-market	(5)	6
Depreciation and amortization expense	4	4
Distributions from unconsolidated affiliates, net of earnings	(3)	13
Other charges	9	—
Adjusted segment EBITDA	$ 92	$ 117

(a) Includes $3 million in the lower of cost or market adjustments for the three months ended March 31, 2016. There were no lower of cost or market adjustments for the three months ended March 31, 2017.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 2 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data” in our Annual Report on Form 10-K for the year ended December 31, 2016. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three months ended March 31, 2017 are the same as those described in our Annual Report on Form 10-K for the year ended December 31, 2016. 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 SEC, 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 Annual Report on Form 10-K for the year ended December 31, 2016.

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 Annual Report on Form 10-K for the year ended December 31, 2016.

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. Our positions as of May 5, 2017 were as follows:

Commodity Swaps

Period	Commodity	Notional Volume - Short Positions	Reference Price	Price Range
April 2017 — June 2017	Natural Gas	(67,500) MMBtu/d	NYMEX Final Settlement Price (b)	$2.77-$4.27/MMBtu
July 2017 — September 2017	Natural Gas	(62,500) MMBtu/d	NYMEX Final Settlement Price (b)	$3.20-$4.27/MMBtu
October 2017 — December 2017	Natural Gas	(60,000) MMBtu/d	NYMEX Final Settlement Price (b)	$3.28-$4.27/MMBtu
January 2018 — March 2018	Natural Gas	(22,500) MMBtu/d	NYMEX Final Settlement Price (b)	$3.54-$3.60/MMBtu
April 2017 — December 2017	NGLs	(20,360) Bbls/d (d)	Mt.Belvieu (c)	$.25-$1.22/Gal
April 2017 — December 2017	Crude Oil	(3,103) Bbls/d (d)	NYMEX crude oil futures (a)	$49.27-$56.78/Bbl
January 2018 — February 2018	Crude Oil	(2,263) Bbls/d (d)	NYMEX crude oil futures (a)	$54.06-$56.61/Bbl

(a) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract.
(b) NYMEX final settlement price for natural gas futures contracts.
(c) The average monthly OPIS price for Mt. Belvieu TET/Non-TET.
(d) Average Bbls/d per time period.

Our sensitivities for 2017 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 2017, and exclude the impact of non-cash mark-to-market changes on our commodity derivatives. We utilize direct product crude oil, natural gas and NGL derivatives to mitigate a portion of our condensate, natural gas and NGL commodity price exposure. These sensitivities are associated with our condensate, natural gas and NGL volumes that are currently unhedged.

Commodity Sensitivities Net of Cash Flow Protection Activities

	Per Unit Decrease		Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners	
				(Millions)	
Natural gas prices	$	0.10	MMBtu	$	7
Crude oil prices	$	1.00	Barrel	$	4
NGL prices	$	0.01	Gallon	$	5

In addition to the linear relationships in our commodity sensitivities above, additional factors may 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-proceeds and percentage-of-liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as commodity 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.

We estimate the following sensitivities related to the non-cash mark-to-market on our commodity derivatives associated with our open position on 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	$	1
NGL prices	$	0.01	Gallon	$	3

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

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a portion of our expected commodity price risk relating to the equity volumes associated with our gathering and processing activities through the first quarter of 2018.

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 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 trade between imports and exports of liquid natural gas and NGLs. 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 inventory within our natural gas storage operations as of March 31, 2017:

Inventory

Period ended	Commodity	Notional Volume - Long Positions	Fair Value (millions)	Weighted Average Price
March 31, 2017	Natural Gas	11,736,104 MMBtu	$ 32	$2.72/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Fair Value (millions)	Price Range
April 2017-October 2017	Natural Gas	(36,345,000) MMBtu	$ (2)	$2.57-$3.46/MMBtu
April 2017-October 2017	Natural Gas	23,700,000 MMBtu	$ 3	$2.69-$3.38/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 SEC 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 SEC’s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner’s principal executive and principal financial officers (whom we refer to as the "Certifying Officers"), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of March 31, 2017, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of March 31, 2017, our disclosure controls and procedures were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the quarter ended March 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

The information provided in “Commitments and Contingent Liabilities,” included in Note 18 in Item 8 of Part II of our Annual Report on Form 10-K for the year ended December 31, 2016 and Note 17 in Item 1 of Part I of this Quarterly Report on Form 10-Q is incorporated by reference.

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 Annual Report on Form 10-K for the year ended December 31, 2016. 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 Annual Report on Form 10-K for the year ended December 31, 2016. There are no material changes to the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 6. Exhibits

Exhibit Number		Description
2.1	*#	Contribution Agreement, dated December 30, 2016, by and among DCP Midstream, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
3.1	*	Certificate of Limited Partnership of DCP Midstream Partners, LP dated August 5, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on September 16, 2005).
3.2	*	Certificate of Amendment to Certificate of Limited Partnership of DCP Midstream Partners, LP dated January 11, 2017 (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 January 17, 2017).
3.3	*	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).
3.4	*	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).
3.5	*	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).
3.6	*	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated January 1, 2017 (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 January 6, 2017).
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4.10	*	Indenture, dated as of May 21, 2013, by and between DCP Midstream Operating, LP (as issuer and successor to DCP Midstream, LLC) and the Bank of New York Mellon Trust Company, N.A (attached as Exhibit 4.10 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
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10.3	+	DCP Services, LLC 2008 Long-Term Incentive Plan, as amended and restated effective March 1, 2017.
10.4	+	Form of Strategic Performance Unit Grant Agreement under the DCP Services, LLC 2008 Long-Term Incentive Plan.
10.5	+	Form of Restricted Performance Unit Grant Agreement under the DCP Services, LLC 2008 Long-Term Incentive Plan.
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 from the Quarterly Report on Form 10-Q of DCP Midstream, LP for the three months ended March 31, 2017, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity, and (vi) the Notes to the Condensed Consolidated Financial Statements.

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

\+ Denotes management contract or compensatory plan or arrangement.

\# Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DCP Midstream, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

Date: May 10, 2017	By:	/s/ Wouter T. van Kempen
	Name:	Wouter T. van Kempen
	Title:	President and Chief Executive Officer (Principal Executive Officer)
Date: May 10, 2017	By:	/s/ Sean P. O'Brien
	Name:	Sean P. O'Brien
	Title:	Group Vice President and Chief Financial Officer (Principal Financial Officer)

EXHIBIT INDEX

Exhibit Number		Description
2.1	*#	Contribution Agreement, dated December 30, 2016, by and among DCP Midstream, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
3.1	*	Certificate of Limited Partnership of DCP Midstream Partners, LP dated August 5, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on September 16, 2005).
3.2	*	Certificate of Amendment to Certificate of Limited Partnership of DCP Midstream Partners, LP dated January 11, 2017 (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 January 17, 2017).
3.3	*	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).
3.4	*	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).
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+ Denotes management contract or compensatory plan or arrangement.
# Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

Exhibit 10.3

DCP SERVICES, LLC

2008 LONG-TERM INCENTIVE PLAN

(As Amended and Restated Effective March 1, 2017)

DCP SERVICES, LLC
2008 LONG-TERM INCENTIVE PLAN
(As Amended and Restated Effective March 1, 2017)

TABLE OF CONTENTS

DCP SERVICES, LLC
2008 LONG-TERM INCENTIVE PLAN
(As Amended and Restated Effective March 1, 2017)

PURPOSE

The purpose of this DCP Services, LLC 2008 Long-Term Incentive Plan (the "Plan") is to help attract, motivate, and retain qualified key management personnel through a long-term incentive compensation plan that will provide them with competitive compensation opportunities and align their interests with the interests of DCP Midstream and its Affiliates.

1. Definitions

"Affiliate" means, with respect to any person, any other person that directly or indirectly through one or more intermediaries' controls, is controlled by or is under common control with, the person in question. As used herein, the term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through ownership of voting securities, by contract or otherwise, and includes Enbridge and Phillips 66 so long as either party owns a fifty percent (50%) interest in DCP Midstream.

"Award" means a grant of Restricted Phantom Units or Strategic Performance Units granted under the Plan.

"Board" means the Board of Directors of DCP Midstream.

"Change in Control" means the date on which one of the following, each referred to as a "Change in Control Event," shall have occurred with respect to DCP Midstream:

(a) a merger, consolidation, transfer, lease or sale of substantially all of the assets or other capital transaction involving DCP Midstream, as a result of which there is a change in the membership of the Board such that the members of the Board immediately preceding the transaction are in a minority immediately following the transaction, or

(b) liquidation or dissolution of DCP Midstream,

to the extent any such occurrence is consistent with the meaning of "change in control" under Code Section 409A, the final regulations or any subsequent guidance issued regarding a change in control for non-subchapter C-corporations. In the event that the definition of change in control under Code section 409A is broader than Change in Control as defined in this section, the Committee may determine, in its sole discretion, to apply the definition provided in Code Section 409A or any such guidance.

"Code" means the Internal Revenue Code of 1986, as amended.

"Committee" means the Board or such committee of the Board appointed to administer the Plan, if any.

“Company” means DCP Services, LLC, a wholly-owned subsidiary of DCP Midstream, and any successor entities.

“Date of Grant” means the effective date as of which a Restricted Phantom Unit or a Strategic Performance Unit, as the case may be, is granted to a Participant.

“DCP” means DCP Midstream, LP.

“DCP Midstream” means DCP Midstream, LLC.

“DER” means a dividend/distribution equivalent right, being a contingent right granted with respect to a Unit, to receive an amount in cash equal to the cash dividends and/or cash distributions in US dollars, as the case may be, made with respect to the DCP, Enbridge and/or Phillips 66 securities comprising the particular Unit during the period such Award is outstanding with the amount of such dividends and distributions being equal to the Fair Market Value of the Unit.

“Disability” means a “disability” under the Company’s or Participating Employer’s long-term disability plan, provided such definition complies with the requirements of Section 409A of the Code and, in the event it does not, “disability” shall mean the Participant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

“Employee” means any employee of the Company or any Participating Employer.

“Enbridge” means Enbridge, Inc and any successor in interest to Enbridge.

“Executive Deferred Compensation Plan” means the DCP Services, LLC Executive Deferred Compensation Plan, as amended from time to time.

“Fair Market Value” means the closing sales price of a DCP common unit, Enbridge common share or Phillips 66 common share on the principal national securities exchange, using US dollars or other market in which trading in such common unit or common share occurs on the applicable Valuation Date, or to the extent provided in the Grant Agreement, over such period of consecutive business days ending on the Valuation Date, as reported in *The Wall Street Journal* (or other reporting service approved by the Committee). If there is no trading in the common units or common shares on such Valuation Date, the next preceding date on which there was trading shall be used. If a designated period of consecutive business days is provided for in the Grant Agreement and there is no trading on one or more of such days, then only the days for which there was trading shall be used. If the common units or common shares are not traded on a national securities exchange or other market at the time a determination of Fair Market Value is required to be made hereunder, the Fair Market Value per DCP common unit, Enbridge common share and/or Phillips 66 common share shall be deemed to be an amount as determined in good faith by the Committee by applying any reasonable valuation method, which may be an independent third party evaluation; provided, that any such determination shall be made in compliance with the regulations under Code Section 409A. Factors to be considered by the Committee in establishing Fair Market Value shall include as applicable: the value of tangible and intangible assets, the present value of anticipated future cash flows, the market value of stock or equity interests in similar corporations and other entities engaged in substantially similar trades or businesses, the stock of which is to be valued, the value of which can be readily determined through nondiscretionary, objective means (such as through trading prices on an established securities market or an amount paid in an arm's length private transaction), recent arm's length transactions involving the sale or transfer of such stock or equity interests, and other relevant factors such as control premiums or discounts for lack of marketability and whether the valuation method is used for other purposes that have a material economic effect on the service recipient, its stockholders, or its creditors. The use of a valuation method shall take into consideration all available information material to the value of DCP, Enbridge and Phillips 66 at the time of the grant of the Award and the Fair Market Value shall be established not longer than 12 months prior to the date of the grant of the Award.

"Grant" means the grant of a Restricted Phantom Unit or a Strategic Performance Unit, as the case may be, subject to such terms and conditions as may be set forth in the Grant Agreement accompanying such Award.

"Grant Agreement" or "Agreement" means, with respect to a Grant, the agreement accompanying such Grant which sets forth the Performance Schedule (if applicable), Performance Period, vesting and/or other terms and conditions pertaining to that Grant, as established by the Committee.

"Layoff" means an involuntary Termination of Service of a Participant by the Company or Participating Employer for reasons other than "cause" as determined by the Company, in its discretion.

"Participant" means an Employee to whom a Grant has been made pursuant to the Plan.

"Participating Employer" means any Subsidiary which, with the Company's consent, has adopted the Plan as provided for in Section 2(e) of the Plan.

"Performance Period" means the period established in the respective Grant Agreement during which a Strategic Performance Unit is to become earned or, with respect to a Restricted Phantom Unit, Vested.

"Performance Schedule" means the schedule outlining Strategic Performance goals attached to the Strategic Performance Unit Grant Agreement.

"Phillips 66" means Phillips 66 and any successor in interest to Phillips 66.

"Plan Document" means this Plan and any Grant Agreement in respect of any Award.

"Restricted Phantom Unit" means a Unit, the payment of which is not dependent upon a Performance Schedule.

"Retirement" means an Employee's Termination of Service on or after attaining age 55 and completing five (5) continuous years of service with the Company and/or its Affiliates. Service prior to the effective date of the Employee's Grant Agreement shall be included for purposes of this definition.

"Strategic Performance" means any measure established by the Committee in its sole discretion that compares DCP, Enbridge's and/or Phillips 66's performance to the attainment of strategic objectives. The Committee may alter, amend or revise, in its sole discretion, the strategic objectives to be measured for succeeding Performance Periods.

"Strategic Performance Unit" means a Unit that will be paid to a Participant if Strategic Performance for a Performance Period satisfies the Performance Schedule contained in a Grant Agreement.

"Subsidiary" means an entity that is a member of the controlled group of employers with the Company for purposes of Section 414(b) and (c) of the Code.

"Termination of Service" means a Participant ceases to be an Employee for any reason.

"Unit" means a notional unit having a value, as of the applicable Valuation Date, equal to the Fair Market Value of a common share of Enbridge, a common share of Phillips 66 and/or a common unit of DCP, unless provided otherwise in the Grant Agreement approved by the Committee in its discretion.

"Valuation Date" means the date as of which an Award is to be valued, as stated in a Grant Agreement.

"Vest," and the correlative term "Vested," shall mean that the Award has become earned subject to the terms of the Grant Agreement and the Plan.

2. <u>Administration</u>

(a) The Plan shall be administered by the Committee.

(b) The Committee may establish, from time to time and at any time, subject to the limitations of the Plan as set forth herein, such rules and regulations and amendments and supplements thereto, as it deems necessary to comply with applicable law and for the proper administration of the Plan.

(c) Awards granted to an Employee shall be evidenced by a Grant Agreement. All such Grant Agreements may be entered into by the Company as agent for the Participating Employers, but all Awards shall be and remain the liability of the Participating Employer employing the Participant at the time of such Grants.

(d) The Committee's interpretation and construction of the provisions of the Plan and rules and regulations adopted by the Committee shall be final. No member of the Committee or the Board shall be liable for any action taken, or determination made, in respect of the Plan in good faith. Each member of the Committee and each member of the Board shall be fully justified in relying upon or acting in good faith upon any opinion, report, or information furnished in connection with the Plan by any accountant, counsel, or other specialist (including officers of the Company or a Subsidiary, whether or not such persons are Participants in the Plan).

(e) This Plan may be adopted by a Subsidiary upon approval by the Board of Directors of such Subsidiary and the Board or Committee whereupon such entity shall become a Participating Employer.

3. Eligibility and Participation

(a) The Committee shall from time to time determine those Employees who, in its discretion, are to receive Awards, the type of such Awards, and the terms and conditions of any such Grant to be made; provided, in those cases in which the Committee has delegated to the Chief Executive Officer (the "CEO") of DCP Midstream or other officers of DCP Midstream the authority to make such determination with respect to certain classes of Employees, such determinations shall be made by the CEO or such officers, as applicable.

(b) Each Grant shall be evidenced by a Grant Agreement in such form and with such terms and conditions, as the Committee may from time to time determine. The rights of a Participant with respect to any Grant shall at all times be subject to the terms and conditions set forth in the Grant Agreement relating thereto and in the Plan. Different Grants need not contain terms or conditions similar to any Grant made prior thereto or contemporaneously therewith. The Committee's determinations under the Plan (including determinations of which Employees, if any, are to receive Grants, the form, amount and timing of such Grants, the terms and provisions of such Grants and the agreements evidencing same) need not be uniform and may be made by it selectively among Employees who receive, or are eligible to receive, Grants under the Plan.

4. Grants

4.1 Grant of Awards

(a) The Performance Schedule for each Strategic Performance Unit shall be established by the Committee at the time of Grant. Unless provided otherwise in the Grant Agreement, at the conclusion of each Performance Period Strategic Performance Units, to the extent earned, shall become Vested and payable. A Restricted Phantom Unit shall not be subject to a Performance Schedule unless the Grant Agreement provides otherwise.

(b) The length of each Performance Period shall be for such period as provided in the Grant Agreement.

(c) Except as provided in Sections 4.1(d) and 4.1(e) or provided otherwise in a Participant's Grant Agreement, upon a Participant's Termination of Service, the Participant's Grants and all rights thereunder shall automatically terminate effective at the close of business on the Participant's Termination of Service; provided, however, that in the case of a Participant's

Termination of Service due to Retirement, Disability, Layoff or death after the first anniversary of the initial Date of Grant for the year, unless the Grant Agreement provides otherwise, the Participant shall become contingently Vested in a pro-rata portion of the Award with respect to each Strategic Performance Unit then outstanding based on the number of days in the Performance Period that have lapsed through the date of Termination of Service compared with the total number of days in the Performance Period rounded to the nearest whole Unit, but only to the extent the goals set forth on the Performance Schedule applicable to such Award are achieved, as determined by the Committee, in its sole discretion.

Upon a Participant's Termination of Service the Participant's Grants and all rights thereunder shall automatically terminate effective at the close of business on the Participant's Termination of Service; provided, however, that in the case of a Participant's Termination of Service due to Retirement, Disability, Layoff or death after the first anniversary of the initial grant date for the year, each Restricted Phantom Unit outstanding as of the date of such Termination of Service shall automatically Vest in full, unless the Grant Agreement provides otherwise.

If a Participant's Termination of Service is a result of the Participant's transfer to an Affiliate that is not a Subsidiary, all rights of the Participant with respect to each Award then outstanding shall be determined by the Committee, in its sole discretion.

(d) Notwithstanding Section 4.1(c), in the event a Participant takes an approved leave of absence, or has a Termination of Service for reasons that, in the judgment of the Committee, are deemed to be special circumstances, the Committee may take such action in respect of all or some of the outstanding Grants and Grant Agreements as it may deem appropriate in its discretion under the circumstances.

(e) At the end of each Performance Period, the Committee shall evaluate DCP's Strategic Performance for the purpose of the Strategic Performance Units to determine whether and the extent, if any, in the judgment of the Committee that the performance goals set forth in the Performance Schedule applicable to the Award have been earned for the Performance Period. To the extent earned, any resultant Award payment may nonetheless be reduced or cancelled as a result of the application of the provisions in Section 4.1(c) or may be reduced, cancelled or increased by the Committee, in its sole and absolute discretion, either in individual cases or in the aggregate.

(f) During the Performance Period, an amount equal to the DERs paid with respect to a Restricted Phantom Unit then outstanding shall be paid quarterly in cash to the Participant, unless the Grant Agreement provides otherwise. With respect to Strategic Performance Units an amount equal to the DERs paid with respect to such Award during the Performance Period shall be credited to a notional account (without interest) for the Participant and at the end of the Performance Period the amount credited to such account shall be paid to the Participant in cash, but only with respect to a Strategic Performance Unit that becomes Vested. Any DERs accumulated with respect to a Strategic Performance Unit (or portion thereof) that does not become Vested shall be forfeited at the end of the Performance Period (or its earlier forfeiture date, if applicable).

(g) Awards shall be paid pursuant to their Grant Agreements, but no later than 2½ months following the end of the Plan year in which the Performance Period terminates unless deferred into the Executive Deferred Compensation Plan in accordance with Code Section 409A, less all applicable taxes required to be withheld therefrom. Notwithstanding the foregoing, with respect to any Award that is subject to Section 409A and payable upon separation from service (as defined under Code Section 409A), payment (or deferral into the Executive Deferred Compensation Plan) will be made within the 2-1/2 month period following the Participant's separation from service, except that if the Participant is a specified employee (as defined under Code Section 409A) as of the date of the separation from service, no payment will be made earlier than six months after the date of separation from service. Any payments to which such specified employee would be entitled during the first six months following the date of separation from service will be accumulated and paid on the first day of the seventh month following the date of separation from service.

4.2 Provisions Common to Awards

(a) Awards shall be nontransferable and nonassignable, except that any such Grant may be transferred (i) to such beneficiary as the Participant may designate in the event of death or (ii) by testamentary instrument or by the laws of descent and distribution. The Committee shall prescribe the form and manner in which beneficiary designations shall be made, revoked or amended. Any valid beneficiary designation on file with the Company shall take priority over any conflicting provision of any testamentary or similar instrument.

(b) The establishment of the Plan shall not confer any legal rights upon any Employee or other person to continued employment, nor shall it interfere with the right of the Company or any Participating Employer (which right is hereby reserved) to discharge or demote any Employee and to treat him or her without regard to the effect which that treatment might have upon him or her as a Participant or potential Participant.

(c) In the event that any Participant engages in any activity which the Company determines is detrimental to the Company or any Subsidiary or Affiliate, or otherwise fails to substantially perform his or her obligations or duties as an Employee or is otherwise demoted, the Committee may, at any time prior to payment of an Award to a Participant, cancel or reduce the Award in whole or in part.

5. <u>Amendment or Discontinuance</u>

Subject to the limitations set forth in this Section 5, the Board may at any time and from time to time, without the consent of the Participants, alter, amend, revise, suspend, or discontinue the Plan in whole or in part. Any such amendment shall, to the extent deemed necessary or advisable by the Committee, be applicable to any outstanding Grants theretofore awarded under the Plan, notwithstanding any contrary provisions contained in any Grant Agreement. In the event of any such amendment to the Plan, the holder of any Grant outstanding under the Plan shall, upon request of the Committee and as a condition to the exercisability thereof, execute a conforming amendment in the form prescribed by the Committee to any Grant Agreement relating thereto. Notwithstanding anything contained in this Plan to the contrary, unless required by law, no action contemplated or permitted by this Section 5 shall materially adversely affect any rights of Participants or obligations of the Company to Participants with respect to any award theretofore granted under the Plan without the consent of the affected Participant. In the event that the Plan is terminated, the treatment of an Award that is subject to Section 409A of the Code shall be governed by the following (1) all arrangements that are required to be aggregated with the Plan for purposes of Section 409A, if the Participant participated in all arrangements, are terminated, (2) no payments other than payments that would be payable under the terms of the arrangements if the termination had not occurred are made within 12 months of the termination of the arrangements, (3) all payments are made within 24 months of the termination of the arrangements, and (4) the Company and its affiliates (for purposes of Section 409A) do not adopt a new arrangement that would be aggregated with any terminated arrangement under Regulation §1.409A-1(c) if the same service provider participated in both arrangements, at any time within five years following the date of termination of the arrangement.

6. **Recapitalization, Merger, and Consolidation; Change in Control**

(a) The existence of this Plan and the Awards granted hereunder shall not affect in any way the right or power of the Company or any Participating Employer to make or authorize any or all adjustments, reorganizations, or other changes in its capital structure and its business, or any merger or consolidation of the entity, or the dissolution or liquidation of the entity, or any sale or transfer of all or part of its assets or business, or any other corporate act or proceeding, whether of a similar character or otherwise.

(b) In the event of a Change in Control, the Board, in its sole discretion, may determine the disposition of any Award issued previously or prospectively under the Plan, as long as the Award is not subject to Section 409A of the Code, and may also, in its sole discretion, determine the disposition of the Plan.

7. **Miscellaneous**

(a) Neither the adoption of this Plan nor any action of the Board or the Committee shall be deemed to give any person any right to be granted an Award or any other rights except as may be evidenced by a Grant Agreement, or any amendment thereto, duly authorized by the Committee, and then only to the extent and upon the terms and conditions expressly set forth therein.

(b) The Company or Participating Employer shall have the right to deduct from all amounts paid hereunder all taxes required by law to be withheld with respect to such payments.

(c) THE VALIDITY, CONSTRUCTION AND EFFECT OF THE PLAN, ANY PLAN DOCUMENTS, AND ANY ACTIONS TAKEN OR RELATING TO THE PLAN SHALL BE DETERMINED IN ACCORDANCE WITH THE LAWS OF THE STATE OF COLORADO APPLICABLE TO CONTRACTS MADE AND TO BE PERFORMED WITHIN SUCH STATE.

(d) The Plan shall be unfunded. Neither the Company, any Participating Employer, the Committee, nor the Board shall be required to segregate any assets or secure any liability that may at any time be represented by Grants made pursuant to the Plan.

(e) Notwithstanding anything in the Plan, Grant Agreement or any other plan, agreement or contract to the contrary, with respect to an Award that is subject to Section 409A of the Code, payment of such Award may not be accelerated if such acceleration would result in the payment being subject to tax under Section 409A.

IN WITNESS WHEREOF, the Company has caused the DCP Services, LLC 2008 Long-Term Incentive Plan to be executed on this 27th day of April, effective as of March 1, 2017.

DCP Services, LLC

By: /s/ Tamara L Bray

Tamara L Bray
Group Vice-President
Chief Human Resources Officer

DCP Services, LLC
2008 Long-Term Incentive Plan
Strategic Performance Unit Grant Agreement

Grantee: _____________

Grant Date: _____________

Performance Period: The three-year period beginning on January 1, 2017

1. **<u>Grant of Strategic Performance Units</u>**. DCP Services, LLC (the "Company") hereby grants to you Strategic Performance Units ("SPUs") allocated as ____ Phillips 66 units and _____ Enbridge units under the DCP Services, LLC 2008 Long-Term Incentive Plan (the "Plan") on the terms and conditions set forth herein. The number of SPUs has been determined based on the average closing price of the Phillips 66 (50%) and Enbridge (50%) equity during the last twenty trading days immediately prior to the Grant Date and includes a tandem Dividend Equivalent Right ("DER") grant with respect to each SPU. The Company will establish a DER bookkeeping account for you with respect to each SPU granted that shall be credited with an amount equal to the cash dividends, expressed in US dollars, made during the Performance Period with respect to the Phillips 66 and Enbridge common shares. Unless otherwise defined herein, terms used, but not defined, in this Grant Agreement shall have the same meaning as set forth in the Plan.

2. **<u>Performance Goals and Vesting</u>**. The SPUs granted hereunder shall become Vested only if (i) the Strategic Performance goals set forth in the Performance Schedule attached hereto are achieved at the end of the Performance Period and (ii) you have not incurred a Termination of Service prior to the end of the Performance Period, except as provided in Paragraph 3 below. To the extent the Strategic Performance goals are not achieved, the SPUs shall be forfeited automatically at the end of the Performance Period without payment.

3. **<u>Contingent Vesting Events</u>**. You may become contingently Vested prior to the end of the Performance Period as provided below, but unless the Strategic Performance goals for the Performance Period are achieved, you will not become entitled to a payment with respect to SPUs.

(a) **<u>Death, Disability, Retirement or Layoff</u>**. If you incur a Termination of Service after the first anniversary of your initial Grant Date for the year, as a result of your death, Disability, Retirement or Layoff, a percentage of your SPUs will become contingently Vested in a pro-rata share (rounded to the nearest whole SPU) based on the number of days in the Performance Period that have lapsed through the date of your Termination of Service over the total number of days in the Performance Period. The number of your SPUs that do not become contingently Vested as provided above will be forfeited automatically on the date of your Termination of Service without payment.

(b) **<u>Other Terminations of Service</u>**. If your Termination of Service occurs prior to the end of the Performance Period for any reason other than as provided in Paragraph 3(a) above, all of your SPUs shall be forfeited without payment automatically upon the date of your Termination of Service.

4. **<u>Transfer of Partnership Interests by Phillips 66 or Enbridge</u>**. In the event the membership interest of either Phillips 66 or Enbridge in DCP Midstream, LLC is transferred, then the SPUs allocated based on the transferring entity may be modified to use the common stock of any such successor owner of DCP Midstream, LLC as determined in the sole discretion of the Compensation Committee.

5. **Payments**.

(a) **SPUs**. As soon as administratively practicable after the last day of the Performance Period the Committee will determine whether, and the extent to which, the Strategic Performance goals set forth on the Performance Schedule have been achieved and the number of your SPUs that have become Vested as a result of such achievement. The Company will then pay you in cash, an amount equal to the average closing price of your Vested SPUs based on the last twenty trading days immediately prior to the end of the Performance Period, less any taxes the Company is required to withhold from such payment. Payment will be made as soon as practicable after the end of the Performance Period, but no later than 2½ months following the end of the Plan year in which the Performance Period terminates unless deferred into the Executive Deferred Compensation Plan in accordance with Code Section 409A less all applicable taxes required to be withheld therefrom.

(b) **DERs**. As soon as administratively practicable after the end of the Performance Period (but no later than 2½ months following the end of the calendar year in which the Performance Period terminates), the Company shall pay you in cash, with respect to each SPU that became Vested at the end of the Performance Period, an amount equal to the DERs credited to your DER account during the Performance Period with respect to such Vested SPUs, less any taxes the Company is required to withhold from such payment.

6. **Limitations Upon Transfer**. All rights under this Agreement shall belong to you alone and may not be transferred, assigned, pledged, or hypothecated by you in any way (whether by operation of law or otherwise), other than by will or the laws of descent and distribution or by a beneficiary designation form filed with the Company in accordance with the procedures established by the Company for such designation, and shall not be subject to execution, attachment, or similar process. Upon any attempt by you to transfer, assign, pledge, hypothecate, or otherwise dispose of such rights contrary to the provisions in this Agreement or the Plan, or upon the levy of any attachment or similar process upon such rights, such rights shall immediately become null and void.

7. **Binding Effect**. This Agreement shall be binding upon and inure to the benefit of any successor or successors of the Company and upon any person lawfully claiming under you.

8. **Entire Agreement**. This Agreement along with the Plan constitutes the entire agreement of the parties with regard to the subject matter hereof, and contains all the covenants, promises, representations, warranties and agreements between the parties with respect to the SPUs granted hereby. Without limiting the scope of the preceding sentence, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect.

9. **Modifications**. Any modification of this Agreement shall be effective only if it is in writing and signed by both you and an authorized officer of the Company.

10. **Governing Law**. This grant shall be governed by, and construed in accordance with, the laws of the State of Colorado, without regard to conflicts of laws or principles thereof.

11. **Plan Controls**. By accepting this Grant, you acknowledge and agree that the SPUs are granted under and governed by the terms and conditions of this Agreement and the Plan, a copy of which has been furnished to you. In the event of any conflict between the Plan and this Agreement, the terms of the Plan shall control. All decisions or interpretations of the Committee upon any questions relating to the Plan or this Agreement are binding, conclusive and final on all persons.

DCP Services, LLC

By: __________________
Name: __________________
Title: __________________

Grantee Acknowledgement and Acceptance

By: __________________
Name: __________________

Exhibit 10.4

Performance Schedule

DCP Services, LLC
2008 Long-Term Incentive Plan
Restricted Phantom Unit Grant Agreement

Grantee: _____________

Grant Date: _____________

Performance Period: The three-year period beginning on January 1, 2017

1. **Grant of Restricted Phantom Units**. DCP Services, LLC (the "Company") hereby grants to you Restricted Phantom Units ("RPUs") allocated as _____ Phillips 66 units and _____ Enbridge units under the DCP Services, LLC 2008 Long-Term Incentive Plan (the "Plan") on the terms and conditions set forth herein. The number of RPUs has been determined based on the average closing price of the Phillips 66 (50%) and Enbridge (50%) equity during the last twenty trading days immediately prior to the Grant Date and includes a tandem Dividend Equivalent Right ("DER") grant with respect to each RPU. The Company will establish a DER bookkeeping account for you with respect to each RPU granted that shall be credited with an amount equal to the cash dividends, expressed in US dollars, made during the Performance Period with respect to the Phillips 66 and Enbridge common shares. Unless otherwise defined herein, terms used, but not defined, in this Grant Agreement shall have the same meaning as set forth in the Plan.

2. **Vesting**. Except as provided in Paragraph 3 below, the RPUs granted hereunder shall become Vested only if you have not incurred a Termination of Service prior to the end of the Performance Period.

3. **Early Vesting Events**. You may become Vested prior to the end of the Performance Period as provided in Paragraph (a) below.

   (a) **Death, Disability, Layoff or Retirement**. If you incur a Termination of Service after the first anniversary of your initial Grant Date for the year, as a result of your death, Disability or Layoff, the Performance Period shall terminate and your RPUs and unpaid DERs will become fully Vested on the date of your Termination of Service. If you incur a Termination of Service after the first anniversary of your initial Grant Date for the year as a result of your Retirement, the Company may, in its sole discretion, vest (fully or on a pro-rata basis) the RPUs and unpaid DERs and terminate the Performance Period.

   (b) **Other Terminations of Service**. If your Termination of Service occurs prior to the end of the Performance Period for any reason other than as provided in Paragraph 3(a) above, the Performance Period shall terminate and all of your RPUs and unpaid DERs shall be forfeited automatically upon the date of your Termination of Service.

4. **Transfer of Partnership Interests by Phillips 66 or Enbridge**. In the event the membership interest of either Phillips 66 or Enbridge in DCP Midstream, LLC is transferred, then the RPUs allocated based on the transferring entity may be modified to use the common stock of any such successor owner of DCP Midstream, LLC as determined in the sole discretion of the Compensation Committee.

5. **Payments**.

   (a) **RPUs**. As soon as administratively practicable after the last day of the Performance Period, you will be paid in cash, an amount equal to the average closing price of your Vested RPUs based on the last twenty trading days immediately prior to the end of the Performance Period, less any taxes the Company is required to withhold from such payment. Payment will be made no later than the 15th day of the third month following the end of the calendar year in which the Performance Period terminates unless deferred into the Executive Deferred Compensation Plan in accordance with Code Section 409A.

(b) **DERs**. As soon as practicable after the end of each calendar quarter during the Performance Period, the Company shall pay you in cash, with respect to each RPU, an amount equal to the DERs credited to your DER account during that calendar quarter, less any taxes the Company is required to withhold from such payment.

6. **Limitations Upon Transfer**. All rights under this Agreement shall belong to you alone and may not be transferred, assigned, pledged, or hypothecated by you in any way (whether by operation of law or otherwise), other than by will or the laws of descent and distribution or by a beneficiary designation form filed with the Company in accordance with the procedures established by the Company for such designation, and shall not be subject to execution, attachment, or similar process. Upon any attempt by you to transfer, assign, pledge, hypothecate, or otherwise dispose of such rights contrary to the provisions in this Agreement or the Plan, or upon the levy of any attachment or similar process upon such rights, such rights shall immediately become null and void.

7. **Binding Effect**. This Agreement shall be binding upon and inure to the benefit of any successor or successors of the Company and upon any person lawfully claiming under you.

8. **Entire Agreement**. This Agreement along with the Plan constitutes the entire agreement of the parties with regard to the subject matter hereof, and contains all the covenants, promises, representations, warranties and agreements between the parties with respect to the RPUs granted hereby. Without limiting the scope of the preceding sentence, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect.

9. **Modifications**. Any modification of this Agreement shall be effective only if it is in writing and signed by both you and an authorized officer of the Company.

10. **Governing Law**. This grant shall be governed by, and construed in accordance with, the laws of the State of Colorado, without regard to conflicts of laws or principles thereof.

11. **Plan Controls**. By accepting this Grant, you acknowledge and agree that the RPUs are granted under and governed by the terms and conditions of this Agreement and the Plan, a copy of which has been furnished to you. In the event of any conflict between the Plan and this Agreement, the terms of the Plan shall control. All decisions or interpretations of the Committee upon any questions relating to the Plan or this Agreement are binding, conclusive and final on all persons.

DCP Services, LLC

By: ______________________________

Name: ______________________________

Title: ______________________________

Grantee Acknowledgement and Acceptance

By: ______________________________

Name: ______________________________

DCP Midstream, LP
Ratio of Earnings to Fixed Charges

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

	Three Months Ended March 31,	Year Ended December 31,				
	2017	**2016 (a)**	**2015 (a)**	**2014 (a)**	**2013 (a)**	**2012 (a)**
	(Millions)					
Earnings from continuing operations before fixed charges:						
Pretax income from continuing operations attributable to partners before earnings from unconsolidated affiliates	$ 28	$ (148)	$ (1,157)	$ 476	$ 554	$ 546
Fixed charges	75	324	355	322	290	274
Amortization of capitalized interest	2	7	7	6	5	4
Distributed earnings from unconsolidated affiliates	74	282	184	82	35	34
Less:						
Capitalized interest	(1)	(1)	(32)	(34)	(40)	(79)
Earnings from continuing operations before fixed charges	$ 178	$ 464	$ (643)	$ 852	$ 844	$ 779
Fixed charges:						
Interest expense, net of capitalized interest	72	300	310	277	239	185
Capitalized interest	1	1	32	34	40	79
Estimate of interest within rental expense	—	2	2	1	2	2
Amortization of deferred loan costs	2	21	11	10	9	8
Total fixed charges	$ 75	$ 324	$ 355	$ 322	$ 290	$ 274
Ratio of earnings to fixed charges (b)	2.37	1.43	—	2.65	2.91	2.84

(a) The financial information for the the years ended December 31, 2016, 2015, 2014, 2013 and 2012 includes the results of The DCP Midstream Business, which we acquired from DCP Midstream, LLC on January 1, 2017. This transfer of net assets between entities under common control was 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.

(b) Earnings for the year ended December 31, 2015 were inadequate to cover fixed charges by $998 million.

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or loss from continuing operations attributable to partners before earnings from unconsolidated affiliates, plus fixed charges, plus distributed earnings from unconsolidated affiliates, less capitalized interest. Fixed charges consist of interest expense, 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, LP for the three months ended March 31, 2017;

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: May 10, 2017

/s/ Wouter T. van Kempen

Wouter T. van Kempen
President and Chief Executive Officer
(Principal Executive Officer)
DCP Midstream GP, LLC, general partner of
DCP Midstream GP, LP, general partner of
DCP Midstream, LP

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, LP for the three months ended March 31, 2017;

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: May 10, 2017

/s/ Sean P. O'Brien

Sean P. O'Brien

Group Vice President and Chief Financial Officer

(Principal Financial Officer)

DCP Midstream GP, LLC, general partner of
DCP Midstream GP, LP, general partner of
DCP Midstream, LP

Exhibit 32.1

Certification of President and 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 President and Chief Executive Officer of DCP Midstream GP, LLC, general partner of DCP Midstream GP, LP, general partner of DCP Midstream, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the three months ended March 31, 2017, 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
President and Chief Executive Officer
(Principal Executive Officer)
May 10, 2017

A signed original 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 Group Vice President and 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 Group Vice President and Chief Financial Officer of DCP Midstream GP, LLC, general partner of DCP Midstream GP, LP, general partner of DCP Midstream, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the three months ended March 31, 2017, 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)
May 10, 2017

A signed original 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.