DCP Midstream, LLC
Consolidated Financial Statements for the Years Ended December 31, 2016, 2015 and 2014

TABLE OF CONTENTS

	Page
Independent Auditors' Report	i
Consolidated Balance Sheets	1
Consolidated Statements of Operations	2
Consolidated Statements of Comprehensive (Loss) Income	3
Consolidated Statements of Changes in Equity	4
Consolidated Statements of Cash Flows	5
Notes to Consolidated Financial Statements	6

Deloitte & Touche LLP
Suite 3600
555 Seventeenth Street
Denver, CO 80202-3942
USA

Tel: + 1 303 292 5400
Fax: + 1 303 312 4000
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated financial statements of DCP Midstream, LLC and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive (loss) income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of DCP Midstream, LLC and its subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in accordance with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

February 17, 2017

DCP MIDSTREAM, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 492	$ 3
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $4 million for both periods	656	444
Affiliates	134	75
Other	6	21
Inventories	72	51
Unrealized gains on derivative instruments	42	156
Other	87	50
Total current assets	1,489	800
Property, plant and equipment, net	9,069	9,428
Investments in unconsolidated affiliates	2,969	2,992
Intangible assets, net	137	149
Goodwill	236	242
Unrealized gains on derivative instruments	5	19
Other long-term assets	201	251
Total assets	$ 14,106	$ 13,881
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 677	$ 480
Affiliates	48	40
Other	10	25
Current maturities of long-term debt	500	—
Unrealized losses on derivative instruments	91	69
Accrued interest	72	72
Accrued taxes	68	38
Other	192	172
Total current liabilities	1,658	896
Deferred income taxes	28	26
Long-term debt	5,326	5,669
Unrealized losses on derivative instruments	1	12
Other long-term liabilities	199	187
Total liabilities	7,212	6,790
Commitments and contingent liabilities		
Equity:		
Members' interest	4,628	4,691
Accumulated other comprehensive loss	(4)	(4)
Total members' equity	4,624	4,687
Noncontrolling interests	2,270	2,404
Total equity	6,894	7,091
Total liabilities and equity	$ 14,106	$ 13,881

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
Operating revenues:			
Sales of natural gas and petroleum products	$ 5,317	$ 6,030	$ 11,378
Sales of natural gas and petroleum products to affiliates	952	765	2,030
Transportation, storage and processing	647	532	517
Trading and marketing (losses) gains, net	(23)	119	88
Total operating revenues	6,893	7,446	14,013
Operating costs and expenses:			
Purchases of natural gas and petroleum products	4,970	5,571	11,361
Purchases of natural gas and petroleum products from affiliates	483	418	467
Operating and maintenance	692	742	780
Depreciation and amortization	379	376	348
Asset impairments	—	912	18
General and administrative	301	278	281
Other income	(87)	—	—
(Gain) loss on sale of assets, net	(35)	(42)	7
Restructuring costs	13	11	—
Total operating costs and expenses	6,716	8,266	13,262
Operating income (loss)	177	(820)	751
Earnings from unconsolidated affiliates	283	182	83
Interest expense, net	(321)	(320)	(287)
Income (loss) before income taxes	139	(958)	547
Income tax (expense) benefit	(46)	102	(11)
Net income (loss)	93	(856)	536
Net income attributable to noncontrolling interests	(156)	(86)	(248)
Net (loss) income attributable to members' interests	$ (63)	$ (942)	$ 288

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
Net income (loss)	$ 93	$ (856)	$ 536
Other comprehensive income:			
Reclassification of cash flow hedge losses into earnings	—	2	2
Total other comprehensive income	—	2	2
Total comprehensive income (loss)	93	(854)	538
Total comprehensive income attributable to noncontrolling interests	(156)	(87)	(249)
Total comprehensive (loss) income attributable to members' interests	$ (63)	$ (941)	$ 289

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Members' Equity			
	Members' Interest	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
	(millions)			
Balance, January 1, 2014	$ 2,670	$ (6)	$ 1,725	$ 4,389
Net income	288	—	248	536
Other comprehensive income	—	1	1	2
Dividends and distributions	(474)	—	(252)	(726)
Issuance of common units by DCP Midstream, LP, net of offering costs	146	—	856	1,002
Balance, December 31, 2014	2,630	(5)	2,578	5,203
Net (loss) income	(942)	—	86	(856)
Other comprehensive income	—	1	1	2
Contributions from members	3,000	—	—	3,000
Dividends and distributions	—	—	(289)	(289)
Issuance of common units by DCP Midstream, LP, net of offering costs	3	—	28	31
Balance, December 31, 2015	4,691	(4)	2,404	7,091
Net (loss) income	(63)	—	156	93
Dividends and distributions	—	—	(290)	(290)
Balance, December 31, 2016	$ 4,628	$ (4)	$ 2,270	$ 6,894

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
Cash flows from operating activities:			
Net income (loss)	$ 93	$ (856)	$ 536
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	379	376	348
Earnings from unconsolidated affiliates	(283)	(182)	(83)
Distributions from unconsolidated affiliates	356	217	141
Deferred income tax expense (benefit)	25	(102)	9
Net unrealized losses (gains) on derivative instruments	139	(46)	(43)
Asset impairments	—	912	18
(Gain) loss on sale of assets, net	(35)	(42)	7
Other, net	43	34	27
Changes in operating assets and liabilities which (used) provided cash:			
Accounts receivable	(255)	491	397
Inventories	(21)	29	16
Accounts payable	199	(401)	(452)
Other, net	34	11	(104)
Net cash provided by operating activities	674	441	817
Cash flows from investing activities:			
Capital expenditures	(144)	(811)	(1,384)
Investments in unconsolidated affiliates, net	(53)	(64)	(161)
Proceeds from sale of assets	163	164	30
Net cash used in investing activities	(34)	(711)	(1,515)
Cash flows from financing activities:			
Payment of dividends and distributions to members	—	—	(474)
Proceeds from long-term debt	3,777	7,216	719
Payment of long-term debt	(3,628)	(7,196)	—
Contribution from member	—	1,500	—
Proceeds from issuance of common units by DCP Midstream, LP, net of offering costs	—	31	1,001
Repayment of commercial paper, net	—	(1,012)	(288)
Distributions to noncontrolling interests	(290)	(289)	(252)
Payment of deferred financing costs	(10)	(4)	(12)
Net cash (used in) provided by financing activities	(151)	246	694
Net change in cash and cash equivalents	489	(24)	(4)
Cash and cash equivalents, beginning of period	3	27	31
Cash and cash equivalents, end of period	$ 492	$ 3	$ 27

See Notes to Consolidated Financial Statements.

1. Description of Business and Basis of Presentation

DCP Midstream, LLC, with its consolidated subsidiaries, or us, we, our, or the Company, is a joint venture owned 50% by Phillips 66 and its affiliates, or Phillips 66, and 50% by Spectra Energy Corp and its affiliates, or Spectra Energy. We operate in the midstream natural gas industry and are engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas and producing, fractionating, transporting, storing and selling natural gas liquids, or NGLs, and recovering and selling condensate. Additionally, we generate revenues by trading and marketing natural gas and NGLs.

During the third quarter of 2016, Spectra Energy entered into an Agreement and Plan of Merger (the "Merger Agreement") with Enbridge Inc. ("Enbridge"), a Canadian corporation, and anticipates completing the proposed merger during the first quarter of 2017. The Merger Agreement provides that, upon closing of the proposed merger, Spectra Energy will continue its separate corporate existence as a wholly owned subsidiary of Enbridge.

DCP Midstream, LP (the “Partnership”), formerly DCP Midstream Partners, LP, is a master limited partnership, of which we act as general partner. On December 30, 2016, we entered into a Contribution Agreement (the “Contribution Agreement”) with the Partnership and DCP Midstream Operating, LP (the “Operating Partnership”), a wholly 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. For additional information regarding the Transaction, see Note 6 - Agreements and Transactions with Related Parties and Affiliates.

As of December 31, 2016 and 2015, we owned an approximate 21% in the Partnership including our limited partner and general partner interests. We also own incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. Our incentive distribution rights currently entitle us to receive the maximum share of 48% of incremental available cash generated by the Partnership. As the general partner of DCP Midstream, LP, we have responsibility for its operations.

We are governed by a five-member board of directors, consisting of two voting members from each of Phillips 66 and Spectra Energy and our Chairman of the Board, President and Chief Executive Officer, a non-voting member. All decisions requiring the approval of our board of directors are made by simple majority vote of the board, but must include at least one vote from both a Phillips 66 and Spectra Energy board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Phillips 66 and Spectra Energy.

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. These consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. We also consolidate DCP Midstream, LP, a variable interest entity for which we are the primary beneficiary, and where the limited partners do not have substantive kick-out or participating rights. 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. Intercompany balances and transactions have been eliminated in consolidation.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the 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.

Cash and Cash Equivalents — Cash and cash equivalents include all cash balances and investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less and temporary investments of cash in short-term money market securities.

Allowance for Doubtful Accounts — Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon the number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

Inventories — Inventories, which consist primarily of natural gas and NGLs held in storage for transportation, processing and sales commitments, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management and Derivative Activities and Financial Instruments — We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives may be designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales contract. The remaining other non-trading derivatives, which are related to asset based activities for which hedge accounting or the normal purchase or normal sale exception is not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Other Non-Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses

(a) Mark-to-market method — An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in trading and marketing gains and losses during the current period.
(b) Hedge method — An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.
(c) Accrual method — An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery impacts earnings.

Cash Flow and Fair Value Hedges — For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The change in fair value of the effective portion of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as accumulated other comprehensive income, or AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same line item as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. The change in fair value of all derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated statements of operations.

Valuation — 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 internally developed pricing models developed primarily from historical relationships with quoted market prices and the 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.

Property, Plant and Equipment — Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Capitalized Interest — We capitalize interest during construction of major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

Asset Retirement Obligations — Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a credit-adjusted risk free interest rate and accretes due to the passage of time based on the time value of money until the obligation is settled.

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation

each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Goodwill and Intangible Assets — Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We perform an annual impairment test of goodwill in the third quarter, and update the test during interim periods when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of a reporting unit. We primarily use a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information (including forecasted commodity prices and volumes), as well as historical and other factors. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. Adverse changes in our business or the overall operating environment such as declines in gas production volumes, loss of significant customers or a decrease in commodity prices may affect our estimate of future operating results, which could result in future goodwill and intangible assets impairment charges.

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Investments in Unconsolidated Affiliates — We use the equity method to account for 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.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred and if the loss is other than temporary. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Long-Lived Assets — We evaluate whether the carrying value of long-lived assets, including intangible assets, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- a significant adverse change in legal factors or business climate;
- a current period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We determine the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets. A prolonged period of lower commodity prices or declines in production volumes may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Unamortized Debt Premium, Discount and Expense — Premiums, discounts and costs incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. The premiums, discounts and unamortized costs are recorded on the consolidated balance sheets within the carrying amount of long-term debt.

Noncontrolling Interest — Noncontrolling interest represents the ownership interests of third-party entities in the net assets of consolidated affiliates, including the ownership interest of the Partnership's public unitholders, through the Partnership's publicly traded common units, in net assets of the Partnership and the noncontrolling interest which is recorded in the Partnership's consolidated balance sheets. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third-party investors.

Dividends and Distributions — Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Phillips 66 and Spectra Energy based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Phillips 66 and Spectra Energy. Tax distributions to the members are calculated based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due. Our board of directors determines the amount of the periodic dividends to be paid by considering net income attributable to members' interests, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. Dividends are allocated to the members in accordance with their respective ownership percentages.

The Partnership considers the payment of a quarterly distribution to the holders of its common units, to the extent the Partnership has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a 100% owned subsidiary of ours. There is no guarantee, however, that the Partnership will pay the minimum quarterly distribution on the units in any quarter. The Partnership will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement.

Revenue Recognition — We generate the majority of our revenues from gathering, processing, compressing, treating, transporting, storing and selling natural gas and producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas, NGLs and condensate, or by receiving fees.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

- *Percent-of-proceeds/index arrangements* — Under percent-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas, NGLs and condensate based on published index prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices or contractual recoveries for the natural gas, NGLs and condensate, regardless of the actual amount of the sales proceeds we

receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquid arrangements, we do not keep any amounts related to the residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs, in lieu of us returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds/index arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly to the price of NGLs and condensate.

- *Fee-based arrangements* — Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas and fractionating, storing and transporting NGLs. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes our revenues from these arrangements would be reduced.

- *Keep-whole and wellhead purchase arrangements* — Under the terms of a keep-whole processing contract, natural gas is gathered from the producer for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer with a British thermal unit, or Btu, content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under the terms of a wellhead purchase contract, we purchase natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are exposed to the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of residue natural gas, or frac spread. We benefit in periods when NGL prices are higher relative to natural gas prices when that frac spread exceeds our operating costs.

Our trading and marketing of natural gas and NGL products consists of physical purchases and sales, as well as derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* — Our customary practice is to enter into a written contract.

- *Delivery* — Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

- *The fee is fixed or determinable* — We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

- *Collectability is reasonably assured* — Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, credit metrics, liquidity and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the cash is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. New or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the consolidated statements of operations as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the settlement of financial and physical energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2016, 2015 and 2014.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable - other, as of December 31, 2016 and 2015, were imbalances totaling $6 million and $21 million, respectively. Included in the consolidated balance sheets as accounts payable - other, as of December 31, 2016 and 2015, were imbalances totaling $10 million and $25 million, respectively.

Purchases of natural gas, propane and NGLs — Purchases of natural gas and NGLs represent physical purchases from suppliers. We purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries.

Significant Customers — There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2016, 2015 or 2014. We had significant transactions with affiliates for the years ended December 31, 2016, 2015 and 2014. See Note 6, Agreements and Transactions with Related Parties and Affiliates.

Environmental Expenditures — Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not generate current or future revenue, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

Equity-Based Compensation — 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.

Accounting for Sales of Units by a Subsidiary — We account for sales of units by a subsidiary by recording an increase or decrease in members' interest within equity equal to the amount of net proceeds received in excess or deficit of the carrying value of the units sold. The remaining net proceeds are recorded as an increase to noncontrolling interest.

Income Taxes — We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries.

We follow the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal income tax returns of each member.

3. Recent 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 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 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, with the option to early adopt for financial statements that have not been issued. The impact of this ASU will be evaluated upon the occurrence of future business combinations and provisional adjustments will be recorded in the period determined.

FASB ASU 2015-02 "Consolidation (Topic 810): Amendments to the Consolidation Analysis," or ASU 2015-02 — In February 2015, the FASB issued ASU 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This ASU was effective for annual reporting periods beginning after December 15, 2015. The retrospective adoption of this ASU has been implemented and did not have any impact on our 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.

4. Variable Interest Entities

ASU 2015-02 amended the conditions used to evaluate whether an entity is a variable interest entity. Following this amendment, a limited partnership is considered a variable interest entity unless a simple majority of the limited partners have substantive kick-out or participating rights. Upon the adoption of ASU 2015-02 in 2016, DCP Midstream, LP is considered a variable interest entity because the limited partners do not have substantive kick-out or participating rights. We are the primary beneficiary of the Partnership because we have the power to direct the significant activities and the obligation to receive the benefits or absorb the losses of those significant activities of the Partnership. As such, we consolidate the Partnership and recognize non-controlling interest. Prior to the adoption of ASU 2015-02, the Partnership was not a variable interest entity, however, we consolidated the Partnership under the voting interest model as we controlled the entity through our ownership and general partner interest, and the limited partners did not have substantive kick-out or participating rights.

The following table represents amounts included in our consolidated balance sheets attributable to our variable interest entity:

	December 31, 2016		December 31, 2015		Classification
	(millions)				
Assets/liabilities:					
Cash and cash equivalents	$	1	$	2	*Cash and cash equivalents*
Accounts receivable — trade	$	62	$	73	*Accounts receivable — trade*
Inventories	$	44	$	43	*Inventories*
Unrealized gains on derivative instruments	$	1	$	73	*Unrealized gains on derivative instruments*
Other current assets	$	10	$	2	*Other current assets*
Property, plant and equipment, net	$	3,272	$	3,476	*Property, plant and equipment, net*
Investments in unconsolidated affiliates	$	1,475	$	1,493	*Investments in unconsolidated affiliates*
Intangible assets, net	$	103	$	112	*Intangible assets, net*
Goodwill	$	72	$	72	*Goodwill*
Other long-term assets	$	12	$	9	*Other long-term assets*
Accounts payable — trade	$	108	$	98	*Accounts payable — trade*
Accounts payable — affiliates	$	3	$	4	*Accounts payable — affiliates*
Unrealized losses on derivative instruments	$	7	$	—	*Unrealized losses on derivative instruments*
Accrued interest	$	18	$	19	*Accrued interest*
Accrued taxes	$	19	$	12	*Accrued taxes*
Other current liabilities	$	29	$	34	*Other current liabilities*
Current maturities of long-term debt	$	500	$	—	*Current maturities of long-term debt*
Long-term debt	$	1,750	$	2,424	*Long-term debt*
Other long-term liabilities	$	44	$	47	*Other long-term liabilities*

The assets of the Partnership are the property of the Partnership and are not available to us for any other purpose, including as collateral for our debt securities and credit facilities with financial institutions (see Notes 12 and 18). The Partnership's asset balances can only be used to settle its own obligations. The liabilities of the Partnership do not represent additional claims against our general assets and the creditors or beneficial interest holders of the Partnership do not have recourse to our general credit. Our maximum exposure to loss as a result of our involvement with the Partnership includes our equity investment. During the years ended December 31, 2016 and 2015, we did not provide any financial support to the Partnership that we were not contractually obligated to provide under the services agreement we have with the Partnership, which requires the Partnership to reimburse us for fees and other costs incurred by us on behalf of the Partnership.

5. Dispositions

In May 2016, the Partnership entered into a purchase and sale agreement with a third party to sell its 100% interests in its Northern Louisiana system, which primarily consisted of certain gas processing plants and gathering systems, for approximately $160 million, subject to customary purchase price adjustments. This transaction closed on July 1, 2016, and we recognized a $41 million gain on sale, net of goodwill, in our consolidated statements of operations for the year ended December 31, 2016.

6. Agreements and Transactions with Related Parties and Affiliates

DCP Midstream, LP

Contribution Agreement

On January 1, 2017, we contributed to the Partnership: (i) our ownership interests in all of our 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 and 2,550,644 general partner units to us in a private placement and (ii) the Operating Partnership assumed $3,150 million of our debt. This represents a Transaction between entities under common control and a change in reporting entity. There is no financial statement impact for the year ended December 31, 2016.

Pursuant to the Contribution Agreement, we agreed 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, we 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 us, as 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.

Services Agreement

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 DCP Midstream and the Partnership dated February 14, 2013, as amended (the "Original Services Agreement"). Under the Services Agreement, the Partnership is required to reimburse DCP Midstream, LLC for salaries of personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on the Partnership's behalf. There is no limit on the reimbursements the Partnership makes to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf.

The Partnership paid us an annual fee under the Original Services Agreement for centralized corporate functions performed by us on behalf of the Partnership. Reimbursements received from the Partnership have been eliminated in consolidation. The annual fee paid under the Original Services Agreement was $71 million for the year ended December 31, 2016.

Dividends and Distributions

During the years ended December 31, 2016 and 2015, no tax distributions were paid to the members. During the year ended December 31, 2014, we paid tax distributions of $159 million based on estimated annual taxable income allocated to Phillips 66 and Spectra Energy according to their respective ownership percentages at the date the distributions became due. During the years ended December 31, 2016 and 2015, no dividends were declared or paid. During the year ended December 31, 2014 we declared and paid dividends of $315 million to Phillips 66 and Spectra Energy, allocated in accordance with their respective ownership percentages

The Partnership considers the payment of a quarterly distribution to the holders of its common units, to the extent the Partnership has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a 100% owned subsidiary of ours. There is no guarantee, however, that the Partnership will pay the minimum quarterly distribution on the units in any quarter. The Partnership will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement. During the years ended December 31, 2016, 2015 and 2014, the Partnership paid distributions of $359 million, $358 million and $316 million, respectively, to its limited partners, of which we received $76 million, $76 million and $69 million for our limited partner interests, respectively. Additionally, during the years ended December 31, 2016, 2015 and 2014, we received $124 million, $124 million and $104 million, respectively for our general partner interest, which includes our incentive distribution rights. Distributions from the Partnership eliminate in consolidation.

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 27% of our NGL production was committed to Phillips 66 and CPChem as of December 31, 2016, the primary production commitment of which 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.

Spectra Energy

We purchase natural gas and other NGL products from, and provide gathering, transportation and other services to Spectra Energy. We anticipate continuing to purchase commodities and provide services to Spectra Energy 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 between 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.

Competition

Our related parties or affiliates, including DCP Midstream, LP, Phillips 66 and Spectra Energy, are not restricted, under either the LLC Agreement or the Services Agreement, from competing with us. Our related parties or affiliates, including the Partnership, Phillips 66 and Spectra Energy, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

The following table summarizes our transactions with related parties and affiliates:

	Year Ended December 31,		
	2016	2015	2014
	(millions)		
Phillips 66 (including CPChem):			
Sales of natural gas and petroleum products to affiliates	$ 909	$ 695	$ 1,960
Purchases of natural gas and petroleum products from affiliates	$ 18	$ —	$ 11
Operating and maintenance and general and administrative expenses	$ 2	$ 4	$ 3
Spectra Energy:			
Transportation, storage and processing	$ —	$ —	$ 14
Purchases of natural gas and petroleum products from affiliates	$ 33	$ 50	$ 88
Operating and maintenance and general and administrative expenses	$ 4	$ 6	$ 10
Unconsolidated affiliates:			
Sales of natural gas and petroleum products to affiliates	$ 43	$ 70	$ 70
Transportation, storage and processing	$ 5	$ 3	$ 12
Purchases of natural gas and petroleum products from affiliates	$ 432	$ 368	$ 368

We had balances with related parties and affiliates as follows:

	December 31, 2016	December 31, 2015
	(millions)	
Phillips 66 (including CPChem):		
Accounts receivable	$ 115	$ 54
Accounts payable	$ 4	$ 3
Other assets	$ 2	$ 1
Spectra Energy:		
Accounts receivable	$ 1	$ —
Accounts payable	$ 3	$ 4
Other assets	$ 1	$ 1
Other liabilities	$ 1	—
Unconsolidated affiliates:		
Accounts receivable	$ 18	$ 21
Accounts payable	$ 41	$ 33
Other assets	$ 5	$ 31

7. Inventories

Inventories were as follows:

	December 31, 2016	December 31, 2015
	(millions)	
Natural gas	$ 28	$ 29
NGLs	44	22
Total inventories	$ 72	$ 51

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the consolidated statements of

operations. We recognized $3 million, $8 million and $24 million in lower of cost or market adjustments during the years ended December 31, 2016, 2015 and 2014, respectively.

8. Property, Plant and Equipment

Property, plant and equipment by classification were as follows:

	Depreciable Life	December 31, 2016	December 31, 2015
		(millions)	
Gathering and transmission systems	20 - 50 years	$ 8,560	$ 8,815
Processing, storage and terminal facilities	35 - 60 years	5,134	5,102
Other	3 - 30 years	502	485
Construction work in progress		171	196
Property, plant and equipment		14,367	14,598
Accumulated depreciation		(5,298)	(5,170)
Property, plant and equipment, net		$ 9,069	$ 9,428

Interest capitalized on construction projects was less than $1 million for the year ended December 31, 2016. Interest capitalized on construction projects for the years ended December 31, 2015 and 2014 was $32 million and $34 million, respectively.

Depreciation expense for the years ended December 31, 2016, 2015 and 2014 was $367 million, $357 million and $327 million, respectively.

Asset Retirement Obligations

As of December 31, 2016 and 2015, we had $124 million and $120 million, respectively, of asset retirement obligations, or AROs, in other long-term liabilities in the consolidated balance sheets. Accretion expense is recorded within operating and maintenance expense in our consolidated statements of operations.

We identified various assets as having an indeterminate life, for which fair value is not estimable 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 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 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.

The following table summarizes changes in the asset retirement obligations included in our balance sheets:

	December 31, 2016	December 31, 2015
	(millions)	
Balance, beginning of period	$ 120	$ 117
Accretion expense	7	7
Revisions in estimated cash flows	(3)	(4)
Balance, end of period	$ 124	$ 120

9. Investments in Unconsolidated Affiliates

We had investments in the following unconsolidated affiliates accounted for using the equity method:

	Percentage Ownership	December 31, 2016	December 31, 2015
		(millions)	
DCP Sand Hills Pipeline, LLC	66.67%	$ 1,507	$ 1,492
DCP Southern Hills Pipeline, LLC	66.67%	754	764
Discovery Producer Services, LLC	40.00%	385	405
Front Range Pipeline LLC	33.33%	165	170
Texas Express Pipeline LLC	10.00%	93	96
Panola Pipeline Company, LLC	15.00%	25	19
Mont Belvieu Enterprise Fractionator	12.50%	23	25
Mont Belvieu I Fractionation Facility	20.00%	10	11
Other unconsolidated affiliates	Various	7	10
Total investments in unconsolidated affiliates		$ 2,969	$ 2,992

There was an excess of the carrying amount of the investment over the underlying equity of Sand Hills of $662 million and $677 million as of December 31, 2016 and 2015, respectively, which is associated with and being amortized over the life of the underlying long-lived assets of Sand Hills.

There was an excess of the carrying amount of the investment over the underlying equity of Southern Hills of $148 million and $152 million as of December 31, 2016 and 2015, respectively, which is associated with, and being amortized over the life of, the underlying long-lived assets of Southern Hills.

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery Producer Services, LLC, or Discovery, of $20 million and $24 million as of December 31, 2016 and 2015, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Discovery.

There was an excess of the carrying amount of the investment over the underlying equity of Front Range of $5 million at both December 31, 2016 and 2015, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Front Range.

There was an excess of the carrying amount of the investment over the underlying equity of Texas Express of $3 million at both December 31, 2016 and 2015, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Texas Express.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I Fractionation Facility, or Mont Belvieu I, of $2 million and $3 million as of December 31, 2016 and 2015, respectively, which is associated with, and is being amortized over the life of the underlying long-lived assets of Mont Belvieu I.

Earnings from unconsolidated affiliates amounted to the following:

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
DCP Sand Hills Pipeline, LLC	$ 110	$ 62	$ 27
Discovery Producer Services, LLC	74	53	7
DCP Southern Hills Pipeline, LLC	44	18	15
Front Range Pipeline LLC	19	17	2
Mont Belvieu Enterprise Fractionator	16	15	17
Mont Belvieu I Fractionation Facility	9	9	12
Texas Express Pipeline LLC	9	8	3
Panola Pipeline Company, LLC	2	—	—
Total earnings from unconsolidated affiliates	$ 283	$ 182	$ 83

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

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
Income statement (a):			
Operating revenues	$ 1,311	$ 1,142	$ 859
Operating expenses	$ 539	$ 541	$ 503
Net income	$ 768	$ 600	$ 354

	December 31, 2016	December 31, 2015
	(millions)	
Balance sheet (a):		
Current assets	$ 232	$ 240
Long-term assets	5,274	5,224
Current liabilities	(156)	(167)
Long-term liabilities	(205)	(230)
Net assets	$ 5,145	$ 5,067

(a) In accordance with the Panola Pipeline Company, LLC, or Panola, joint venture agreement, earnings began to accrue to the Partnership' interest on February 1, 2016. Accordingly, activity related to Panola is included in the above tables as of and for the year ended December 31, 2016.

10. Goodwill

The change in the carrying amount of goodwill was as follows:

	December 31,	
	2016	2015
	(millions)	
Balance, beginning of period	$ 242	$ 704
Impairment	—	(460)
Dispositions	(6)	(2)
Balance, end of period	$ 236	$ 242

We performed our annual goodwill assessment during the third quarter of 2016 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. As a result of our assessment, we concluded that the entire amount of goodwill disclosed on the consolidated balance sheet is recoverable. We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the discount rate, volume forecasts, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information (including forecasted volumes and commodity prices), as well as historical and other factors.

In the second quarter of 2015, we determined that continued weak commodity prices caused a change in circumstances warranting an interim impairment test. Using the fair value approaches described within the Summary of Significant Accounting Policies, we determined that the estimated fair value of our Mid-Continent and Permian reporting units was less than the carrying amount.

The Partnership also performed a goodwill assessment in the second quarter of 2015 and determined that the estimated fair value of its Collbran, Michigan and Southeast Texas reporting units was less than the carrying amount, due to the same factors.

We then allocated the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. In the second quarter of 2015, we and the Partnership recognized goodwill impairment based on our best estimate of the impairment resulting from the performance of the hypothetical purchase price allocation which totaled $378 million for our Mid-continent and Permian reporting units and $49 million for the Partnership's Collbran, Michigan and Southeast Texas reporting units. We and the Partnership completed the hypothetical purchase price allocation in the third quarter of 2015 and after completing the analysis, there was no remaining fair value to assign to goodwill of the Partnership's Collbran reporting unit. As a result, the Partnership recorded an additional impairment of $33 million in the third quarter of 2015.

We performed our annual goodwill assessment during the third quarter of 2015. We concluded and the Partnership concluded that the fair value of goodwill of the remaining reporting units exceeded their carrying value, and the entire amount of goodwill disclosed on the consolidated balance sheet associated with these remaining reporting units is recoverable, therefore, no other goodwill impairments were identified or recorded for the remaining reporting units as a result of the annual goodwill assessment

Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. If our forecast indicates lower commodity prices in future periods at a level and duration that results in producers curtailing or redirecting drilling in areas where we operate, it may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

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 consolidated balance sheets as intangible assets, net, and are as follows:

	December 31,	
	2016	2015
	(millions)	
Gross carrying amount	$ 410	$ 410
Accumulated amortization	(151)	(139)
Accumulated impairment	(122)	(122)
Intangible assets, net	$ 137	$ 149

For the years ended December 31, 2016, 2015 and 2014, we recorded amortization expense of $12 million, $19 million and $21 million, respectively. As of December 31, 2016, the remaining amortization periods ranged from approximately 2 years to approximately 19 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	$ 11
2018	11
2019	11
2020	11
2021	11
Thereafter	82
Total	$ 137

11. 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 13, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

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 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 on the NYMEX exchange 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.

Benefits

We offer certain eligible executives the opportunity to participate in DCP Midstream LP’s Non-Qualified Executive Deferred Compensation Plan, or the EDC Plan. All amounts contributed to and earned by the EDC Plan’s investments are held in a trust account, which is managed by a third-party service provider. The trust account is invested in short-term money market securities and mutual funds. These investments are recorded at fair value, with any changes in fair value being recorded as a gain or loss in our consolidated statements of operations. Given that the value of the short-term money market securities and mutual funds are publicly traded and for which market prices are readily available, these investments are classified within Level 1.

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 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.

There were no assets measured at fair value on a non-recurring basis as of December 31, 2016. The following table presents the carrying value of assets measured at fair value on a non-recurring basis, by consolidated balance sheet caption and by valuation hierarchy, as of December 31, 2015:

	Net Carrying Value	Fair Value Measurements Using			Asset Impairments
		Level 1	Level 2	Level 3	
			(millions)		
December 31, 2015:					
Goodwill	$ —	$ —	$ —	$ —	460
Property, plant and equipment	87	—	—	87	302
Intangible assets	36	—	—	36	122
Other assets	50	—	—	50	28
Total non-recurring assets at fair value	$ 173	$ —	$ —	$ 173	$ 912

The following table presents the financial instruments carried at fair value on a recurring basis, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets:								
Commodity derivatives (a)	$ 5	$ 28	$ 9	$ 42	$ 23	$ 98	$ 35	$ 156
Short-term investments (b)	$ —	$ —	$ —	$ —	$ 2	$ —	$ —	$ 2
Long-term assets:								
Commodity derivatives (c)	$ —	$ —	$ 5	$ 5	$ 3	$ 12	$ 4	$ 19
Mutual funds (d)	$ —	$ —	$ —	$ —	$ 8	$ —	$ —	$ 8
Current liabilities:								
Commodity derivatives (e)	$ (11)	$ (57)	$ (23)	$ (91)	$ (16)	$ (30)	$ (23)	$ (69)
Long-term liabilities:								
Commodity derivatives (f)	$ (1)	$ —	$ —	$ (1)	$ (1)	$ (5)	$ (6)	$ (12)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(b) Includes short-term money market securities included in cash and cash equivalents in our consolidated balance sheets.
(c) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(d) Included in other long-term assets in our consolidated balance sheets.
(e) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(f) Included in long-term unrealized losses on derivative instruments in our 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. Amounts transferred in and out of Level 1 and Level 2 are reflected at fair value as of the end of the period. During the years ended December 31, 2016 and 2015, there were no transfers between Level 1 and Level 2 of the fair value hierarchy.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. The significant unobservable inputs used in determining fair value include adjustments by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the “Transfers into Level 3” and “Transfers 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 rollforwards below, the gains or losses in the tables 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)			
Year Ended December 31, 2016 (a):				
Beginning balance	$ 35	$ 4	$ (23)	$ (6)
Net unrealized gains (losses) included in earnings (b)	3	1	(15)	6
Settlements	(29)	—	15	—
Ending balance	$ 9	$ 5	$ (23)	$ —
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 9	$ 3	$ (23)	$ 6
Year Ended December 31, 2015 (a):				
Beginning balance	$ 23	$ 3	$ (45)	$ (12)
Net unrealized (losses) gains included in earnings (b)	(82)	1	(29)	6
Transfers out of Level 3 (c)	—	—	1	—
Settlements	(25)	—	50	—
Novation (d)	119	—	—	—
Ending balance	$ 35	$ 4	$ (23)	$ (6)
Net unrealized (losses) gains on derivatives still held included in earnings (b)	$ (84)	$ 1	$ (23)	$ 4

(a) There were no purchases, issuances or sales of derivatives or transfers into Level 3 for the year ended December 31, 2016 and 2015.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains, net, in our consolidated statements of operations.
(c) Amounts transferred out of Level 3 are reflected at fair value as of the end of the period.
(d) As a result of the March 2015 novation of certain fixed price commodity derivatives, the Partnership' position no longer eliminates in consolidation.

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 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 these contracts.

Year Ended December 31, 2016:			
Product Group	Fair Value (millions)	Forward Curve Range	
Assets:			
NGLs	$ 14	$0.25-$.1.20	Per gallon
Liabilities:			
NGLs	$ (23)	$0.25-$1.23	Per gallon

Estimated Fair Value of Financial Instruments

Valuation of a contract's fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices

are not available, fair value is determined based on pricing models developed primarily from historical and expected relationship with quoted market prices.

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

The fair value of our interest rate swaps, if applicable, and commodity non-trading derivatives are based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, if applicable, our NGL and crude oil swaps and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third-party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The “prices based on models and other valuation methods” category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the specific market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value. We determine the fair value of our variable rate debt based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers. We classify the fair value of our outstanding debt balances within Level 2 of the fair value hierarchy. As of December 31, 2016 and December 31, 2015, the carrying value and fair value of our long-term debt were as follows:

	December 31, 2016		December 31, 2015	
	Carrying Value (a)	Fair Value	Carrying Value	Fair Value
	(millions)			
Total debt	$ 5,854	$ 5,819	$ 5,669	$ 4,754

(a) Excludes unamortized issuance costs.

12. Financing

	December 31, 2016	December 31, 2015
	(millions)	
DCP Midstream's debt securities:		
Senior notes:		
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	$ 450	$ 450
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 August 2000, interest at 8.125% payable semiannually, due August 2030 (a)	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	450
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semiannually, due May 2043	550	550
DCP Midstream's credit facilities with financial institutions:		
DCP Midstream's revolving credit agreement terminated December 30, 2016, weighted average interest rate of 2.93% at December 31, 2015	—	96
DCP Midstream term-loan, variable interest rate of 3.875% at Dec 31, 2016, due December 2019 (b)	424	—
DCP Midstream LP's debt securities:		
Senior notes:		
Issued November 2012, interest at 2.50% payable semiannually, due December 2017	500	500
Issued March 2014, interest at 2.70% payable semiannually, due April 2019	325	325
Issued March 2012, interest at 4.95% payable semiannually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semiannually, due March 2023	500	500
Issued March 2014, interest at 5.60% payable semiannually, due April 2044	400	400
DCP Midstream LP's credit facilities with financial institutions:		
DCP Midstream, LP's revolving credit agreement, weighted-average variable interest rate of 2.01% and 1.57%, as of December 31, 2016 and December 31, 2015, respectively, due May 2019	195	375
Fair value adjustments related to interest rate swap fair value hedges (a)	24	26
Unamortized issuance costs	(28)	(35)
Unamortized discount	(14)	(18)
Total debt	$ 5,826	$ 5,669
Current maturities of long-term debt	500	—
Total long-term debt	$ 5,326	$ 5,669

(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.

(b) The DCP Midstream term-loan was not assumed by the Partnership in the Transaction.

Approximate future maturities of debt in the year indicated are as follows at December 31, 2016:

	Debt Maturities	
	(millions)	
2017	$	500
2018		—
2019		1,394
2020		600
2021		500
Thereafter		2,850
		5,844
Fair value adjustments related to interest rate swap fair value hedges		24
Unamortized issuance costs		(28)
Unamortized discount		(14)
Total debt	$	5,826

DCP Midstream's Debt Securities

The DCP Midstream debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. The senior debt securities are senior unsecured obligations and the junior subordinated notes are unsecured and rank subordinate in right of payment to all of our existing and future senior debt. The DCP Midstream debt securities are not guaranteed by any of our subsidiaries and are therefore, structurally subordinated to all debt and other liabilities of our subsidiaries. The debt securities include an optional redemption whereby we may elect to redeem the notes, in whole or in part from time-to-time. 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 consolidated balance sheets within the carrying amount of long-term debt and will be amortized over the term of the notes.

DCP Midstream's Credit Facilities with Financial Institutions

In May 2016, we entered into a second amendment of the DCP Midstream Amended and Restated Revolving Credit Agreement, which extended the maturity date from March 2017 to May 2019 and reduced the total borrowing capacity from $1.8 billion to $700 million. The DCP Midstream Amended and Restated Revolving Credit Agreement was terminated on December 30, 2016. In conjunction with the termination of the DCP Midstream Amended and Restated Revolving Credit Agreement, $10 million of unamortized issuance costs were included in interest expense.

On December 30, 2016, we entered into a $424 million credit agreement, or the Term Loan, which matures on December 30, 2019. Proceeds from the Term Loan may be used for general company purposes, including for acquisitions, to refinance existing indebtedness, and in connection with the Transaction. Amounts repaid or prepaid under the Term Loan may not be reborrowed. Each of Phillips 66 and Spectra has guaranteed half of our borrowings under the Term Loan in proportion to their respective ownership percentages in us.

The Term Loan bears interest at either: (1) LIBOR, plus an applicable margin of 1.75% based on our current credit rating; or (2) the base rate, plus an applicable margin of 0.75% based on our current credit rating, where the base rate shall be the higher of (a) The Bank of Tokyo-Mitsubishi UFJ, Ltd.'s prime rate, (b) the federal funds rate plus 0.50%, or (c) LIBOR plus 1.0%.

DCP Midstream, LP's Credit Facilities with Financial Institutions

DCP Midstream, LP has a $1.25 billion senior unsecured revolving credit agreement that matures on May 1, 2019, or the

Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement is used for working capital requirements and other general partnership purposes including acquisitions.

The Partnership's cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings-based pricing grid. Indebtedness under the Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.45% based on the Partnership's current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate, plus 0.50% or the LIBOR Market Index rate, plus 1%, plus (b) an applicable margin of 0.45% based on the Partnership's current credit rating. The Amended and Restated Credit Agreement incurs an annual facility fee of 0.30% based on the Partnership's current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion Amended and Restated Credit Agreement.

As of December 31, 2016, the Partnership had unused borrowing capacity of 1,031 million, net of $24 million of letters of credit, under the Amended and Restated Credit Agreement, all of which was available for working capital and other general partnership purposes. The Partnership's borrowing capacity may be limited by financial covenants set forth in the Amended and Restated Credit Agreement. Except in the case of a default, amounts borrowed under the Amended and Restated Credit Agreement will not become due prior to the May 1, 2019 maturity date.

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

DCP Midstream, LP's Debt Securities

The Partnership's debt securities are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under the DCP Midstream, LP Amended and Restated Credit Agreement. The Partnership is not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at the Partnership's option. The underwriters' fees and related expenses are recorded in our consolidated balance sheets within the carrying amount of long-term debt and will be amortized over the term of the notes.

Other Financing

During the year ended December 31, 2015, the Partnership issued 788,033 of its common units pursuant to its 2014 equity distribution agreement and received proceeds of $31 million, net of commissions and offering costs of less than $1 million, which were used to finance growth opportunities and for general partnership purposes. As of December 31, 2016, approximately $349 million of its common units remained available for sale pursuant to the Partnership's 2014 equity distribution agreement.

In June 2014, the Partnership filed a shelf registration statement on Form S-3 with the U.S. Securities and Exchange Commission, or SEC, with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement allows the Partnership to issue additional common units. In September 2014, the Partnership entered into an equity distribution agreement, or the 2014 equity distribution agreement, with a group of financial institutions as sales agents. The 2014 equity distribution agreement provides for the offer and sale from time to time, through the Partnership's sales agents, of common units having an aggregate offering amount of up to $500 million. During the year ended December 31, 2014, the Partnership issued 2,256,066 of its common units pursuant to the 2014 equity distribution agreement and received proceeds of $119 million, net of commissions and accrued offering costs of $1 million, which were used to finance growth opportunities and for general partnership purposes.

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

13. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

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

with either physical or financial transactions. We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. Our 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 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 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.

DCP Midstream, LP Commodity Cash Flow Hedges

In order for our storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of the Partnership's storage caverns, The Partnership may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when the Partnership brings 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 the Partnership's previously settled base gas cash flow hedges was in a loss position of $6 million as of December 31, 2016.

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. The Partnership is also exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate and may enter into derivative financial instruments due to the same factors. Our and the Partnership's 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 and the Partnership's 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 and the Partnership 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 and the Partnership’s 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 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 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 through 2022 and 2030 and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense, net through 2019, 2020 and 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 27% of our NGL production was committed to Phillips 66 and CPChem as of December 31, 2016, the primary production commitment of which began a ratable wind down period in December 2014 and expires in January 2019. 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.

- Our ISDA counterparties generally have collateral thresholds of zero, requiring us to fully collateralize any commodity contracts in a net liability position, when our or the Partnership's credit rating is below investment grade.

- In some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA contracts, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

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 interest rate swap instruments are in either a net asset or net liability position. As of December 31, 2016, we had less than $1 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability 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 December 31, 2016, we have not been required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2016, the net liability position would be offset by contracts in a net asset position.

Collateral

As of December 31, 2016, we had cash deposits of $71 million, included in other current assets in our 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 December 31, 2016, we held cash of $5 million, included in other current liabilities in our consolidated balance sheet, related to cash postings by third parties and letters of credit of $38 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 in our 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 tables summarize the gross and net amounts of our derivative instruments:

	December 31, 2016		December 31, 2015		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet – Cash Collateral Received (a)	Net Amount
			(millions)		
Assets:					
Commodity derivative instruments	$ 47	$ 47	$ 175	$ (1)	$ 174
Liabilities:					
Commodity derivative instruments	$ (92)	$ (92)	$ (81)	$ —	$ (81)

(a) Included in other current liabilities in our consolidated balance sheets.

Summarized Derivative Information

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

Balance Sheet Line Item	December 31, 2016	December 31, 2015	Balance Sheet Line Item	December 31, 2016	December 31, 2015
	(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	$ 42	$ 156	Unrealized losses on derivative instruments – current	$ (91)	$ (69)
Unrealized gains on derivative instruments – long-term	5	19	Unrealized losses on derivative instruments – long-term	(1)	(12)
	$ 47	$ 175		$ (92)	$ (81)

The following table summarizes the balance and activity within AOCI relative to our interest rate and commodity derivatives, net of noncontrolling interest, as of and for the year ended months ended December 31, 2016:

	Interest Rate Derivatives	Commodity Derivatives	Total
		(millions)	
Net deferred losses in AOCI, beginning balance	$ (1)	$ (3)	$ (4)
Net deferred losses in AOCI, ending balance	$ (1)	$ (3)	$ (4)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ —	$ —	$ —

The following table summarizes the balance and activity within AOCI relative to our interest rate and commodity derivatives, net of noncontrolling interest, as of and for the year ended months ended December 31, 2015:

	Interest Rate Derivatives	Commodity Derivatives	Total
		(millions)	
Net deferred losses in AOCI, beginning balance	$ (2)	$ (3)	$ (5)
Losses reclassified from AOCI – effective portion (a)	1	—	1
Net deferred losses in AOCI, ending balance	$ (1)	$ (3)	$ (4)

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

For the years ended December 31, 2016 and 2015, no derivative gains or losses were recognized in trading and marketing gains, net and interest expense, net, respectively, in our consolidated statements of operations attributable to the ineffective portion of our derivative instruments, as a result of exclusion from effectiveness testing or as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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

	Year Ended December 31,		
Commodity Derivatives: Statement of Operations Line Item	**2016**	**2015**	**2014**
		(millions)	
Realized gains	$ 116	$ 73	$ 45
Unrealized (losses) gains	(139)	46	43
Trading and marketing (losses) gains, net	$ (23)	$ 119	$ 88

The following tables represent, by commodity type, our net long or short derivative positions, as well as the number of outstanding contracts 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 table below. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. These tables also present our net long or short natural gas basis swap positions separately from our net long or short natural gas positions.

	December 31, 2016								
	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls) (a)	Number of Contracts	Net Short Position (MMBtu) (b)	Number of Contracts	Net (Short) Long Position (Bbls) (a)	Number of Contracts		Net Long Position (MMBtu) (b)	Number of Contracts
2017	(1,470,000)	153	(44,981,850)	540	(22,225,821)	348	(c)	6,510,000	83
2018	(251,000)	9	—	—	144,805	25	(d)	912,500	8
2019	(40,000)	2	—	—	(2,203)	2		—	4
2020	(50,000)	2	—	—	240,000	2		—	—

(a) Bbls represents barrels.
(b) MMBtu represents one million British thermal units.
(c) Includes 40 physical index based derivative contracts totaling (16,170,725) Bbls.
(d) Includes 1 physical index based derivative contract totaling (120,000) Bbls.

	December 31, 2015								
	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls)	Number of Contracts	Net Short Position (MMBtu)	Number of Contracts	Net (Short) Long Position (Bbls)	Number of Contracts		Net Long Position (MMBtu)	Number of Contracts
2016	(1,566,672)	119	(25,059,414)	378	(23,575,094)	263	(a)	2,207,500	139
2017	(237,000)	21	(7,387,500)	9	(2,082,157)	40	(b)	4,050,000	4
2018	—	—	—	—	120,000	2		—	—

(a) Includes 37 physical index based derivative contracts totaling (22,972,000) Bbls.
(b) Includes 1 physical index based derivative contract totaling (2,700,000) Bbls.

14. Equity-Based Compensation

We recorded equity-based compensation expense as follows, the components of which are further described below:

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
DCP Midstream, LLC Long-Term Incentive Plan (DCP Midstream LTIP)	$ 18	$ 8	$ 13
DCP Midstream, LP's Long-Term Incentive Plan (DCP Midstream LP's LTIP)	—	—	1
Total	$ 18	$ 8	$ 14

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 December 31, 2016 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:				
Strategic Performance Units (SPUs)	3	$ 6	0%-11%	2
Phantom Units	1-3	$ 5	0%-11%	2

DCP Midstream LTIP — Under the DCP Midstream LTIP, awards may be granted to our key employees. The DCP Midstream LTIP provides for the grant of 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, Spectra Energy 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 our board of directors. All awards are subject to cliff vesting.

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, 2014	230,900	$ 39.30	
Granted	116,790	$ 54.05	
Forfeited	(13,828)	$ 40.75	
Vested (a)	(114,499)	$ 37.72	
Outstanding at December 31, 2014	219,363	$ 47.89	
Granted	111,930	$ 43.25	
Forfeited	(29,283)	$ 48.02	
Vested (b)	(93,551)	$ 41.02	
Outstanding at December 31, 2015	208,459	$ 48.46	
Granted	131,610	$ 45.31	
Forfeited	(8,463)	$ 46.27	
Vested (c)	(98,295)	$ 54.05	
Outstanding at December 31, 2016	233,311	$ 44.41	$ 45.86
Expected to vest	219,844	$ 44.35	$ 45.98

(a) The 2012 grants vested at 115%.
(b) The 2013 grants vested at 115%.
(c) The 2014 grants vested at 130%.

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.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit-based awards related to the strategic performance units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested or paid in cash in 2014	114,499	$ 7	$ 8
Vested or paid in cash in 2015	93,551	$ 4	$ 7
Vested or paid in cash in 2016	98,295	$ 7	$ 4

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, 2014	207,522	$ 40.18	
Granted	122,650	$ 53.73	
Forfeited	(11,130)	$ 41.96	
Vested	(147,840)	$ 42.10	
Outstanding at December 31, 2014	171,202	$ 48.11	
Granted	147,540	$ 47.84	
Forfeited	(17,400)	$ 48.40	
Vested	(96,974)	$ 44.00	
Outstanding at December 31, 2015	204,368	$ 49.85	
Granted	132,870	$ 45.33	
Forfeited	(3,240)	$ 48.62	
Vested	(126,681)	$ 50.13	
Outstanding at December 31, 2016	207,317	$ 46.80	$ 45.97
Expected to vest	185,785	$ 46.72	$ 45.90

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the phantom units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested or paid in cash in 2014	147,840	$ 5	$ 5
Vested or paid in cash in 2015	96,974	$ 3	$ 5
Vested or paid in cash in 2016	126,681	$ 4	$ 5

DCP Midstream LP's LTIP

On April 28, 2016, the unitholders of the Partnership approved the 2016 Long-Term Incentive Plan (the "2016 LTIP"), which replaced the 2005 LTIP that expired pursuant to its terms at the end of 2015 (the "2005 LTIP" and, together with the 2012 LTIP and the 2016 LTIP, the "LTIP"). Any outstanding awards under the 2005 LTIP will remain outstanding and settle according to the terms of such grant. The 2016 plan authorizes up to 900,000 common units to be available for issuance under awards to employees, officers, and non-employee directors of the General Partner and its affiliates. Awards under the 2016 LTIP may include unit options, phantom units, restricted units, distribution equivalent rights, unit bonuses, common unit awards, and performance awards. The 2016 LTIP will expire on the earlier of the date it is terminated by the board of directors of the General Partner or the date that all common units available under the plan have been paid or issued.

Under the Partnership's 2005 LTIP, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for the Partnership. The Partnership's 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. The 2005 LTIP phantom units consist of a notional unit based on the value of the Partnership's common units. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the the Partnership's 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy DCP Midstream GP, LLC's tax withholding obligations, are available for delivery pursuant to other awards. On February 15, 2012, the board of directors of DCP Midstream GP, LLC adopted a 2012 LTIP for employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for the Partnership. The 2012 LTIP provides for the grant of

phantom units and DERs. The 2012 LTIP phantom units consist of a notional unit based on the value of common units or shares of Phillips 66 and Spectra Energy. The LTIPs were administered by the compensation committee of DCP Midstream GP, LLC's board of directors through 2012, and by DCP Midstream GP, LLC's board of directors beginning in 2013. Awards are issued under both LTIPs and all awards are subject to cliff vesting.

Since the Partnership has the intent and ability to settle certain awards within its control in units, the Partnership classifies them as equity awards based on their fair value. The fair value of the Partnership's equity awards is determined based on the closing price of the Partnership's common units at the grant date. Compensation expense on equity awards is recognized ratably over each vesting period. The Partnership accounts 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 the Partnership's common units at each measurement date.

As of December 31, 2016, there was less than $1 million of unrecognized compensation expense related to the DCP Midstream, LP LTIP awards.

15. Benefits

All Company 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 we contribute a range of 4% to 7% of each eligible employee's qualified earnings to the retirement plan, based on years of service. Effective on January 1, 2015, the Company added an automatic enrollment feature in the 401(k) plan, meaning all new employees are enrolled at a 6% contribution level. Employees can opt out of these contribution level or change it at any time. Additionally, we match employees' contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2016, 2015 and 2014, we expensed plan contributions of $29 million, $32 million and $30 million, respectively.

We offer certain eligible executives the opportunity to participate in the 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.

16. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. During the year ended December 31, 2016, we elected to convert our one corporation, a tax paying entity, which files its own federal and state corporate income tax returns, to a limited liability company for federal & state income tax purposes. The income tax benefit (expense) related to this corporation is included in our income tax benefit (expense), along with state and local taxes of the limited liability company and other subsidiaries.

Income tax (expense) benefit consisted of the following:

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
Current:			
Federal income tax expense	$ (19)	$ —	$ —
State income tax expense	(2)	—	(2)
Deferred:			
Federal income tax (expense) benefit	(22)	97	—
State income tax (expense) benefit	(3)	5	(9)
Total income tax (expense) benefit	$ (46)	$ 102	$ (11)

Deferred income tax assets and liabilities consisted of the following:

	December 31, 2016	December 31, 2015
	(millions)	
Deferred income tax assets:		
Net operating loss	$ —	$ 58
Total deferred income tax assets	—	58
Deferred income tax liabilities:		
Property, plant and equipment and intangibles - federal	—	(35)
Property, plant and equipment and intangibles - state	(28)	(26)
Total deferred income tax liabilities	(28)	(61)
Net deferred income tax liabilities	(28)	(3)
Deferred income tax assets, net - noncurrent	—	23
Deferred income tax liabilities, net - noncurrent	(28)	(26)
Net deferred income tax liabilities	$ (28)	$ (3)

The state deferred tax liabilities are primarily associated with Texas franchise taxes. During the year ended December 31, 2016, we recorded a reduction to our net federal deferred tax asset of $58 million resulting from the conversion of our corporation to a limited liability company.

As of December 31 2015, our federal net operating losses were $163 million. The net operating losses were fully utilized upon the conversion of our corporation to a limited liability company during the year ended December 31, 2016.

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

17. Commitments and Contingent Liabilities

Litigation — The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. We are currently named as defendants in some of these cases and customers have asserted individual audit claims related to mismeasurement and mispayment. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These claims, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business, including, from time to time, disputes with customers over various measurement and settlement issues.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

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, which we recorded as other income, net of $2 million in legal fees, in our consolidated statement of operations for the year December 31, 2016.

General 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 consolidated results of operations, financial position or cash flows.

We make expenditures in connection with environmental matters as part of our normal operations. As of December 31, 2016 and December 31, 2015, environmental liabilities included in our consolidated balance sheets as other current liabilities were $4 million and $3 million, respectively. As of both December 31, 2016 and December 31, 2015, environmental liabilities included in our consolidated balance sheets as other long-term liabilities was $9 million.

Operating Leases — We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $37 million, $34 million and $31 million during the years ended December 31, 2016, 2015 and 2014, 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	$ 61
2018	37
2019	35
2020	29
2021	21
Thereafter	42
Total minimum lease payments	$ 225

18. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition, contribution or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, performance of the Partnership or other liabilities related to the assets being acquired, contributed or divested. Claims may be made by third parties or the Partnership under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to 15 years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of

future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities. We have issued guarantees and indemnifications for certain of our consolidated subsidiaries.

19. Restructuring Costs

In April 2016, we announced an approximate 10 percent headcount reduction, which involved the elimination of certain operational and corporate positions, as part of our ongoing effort to create efficiencies, reduce costs and transform our business. As a result of this headcount reduction, we recorded one-time employee termination costs of approximately $13 million, which are included in restructuring costs within total operating costs and expenses in our consolidated statements of operations for the year ended December 31, 2016.

As of December 31, 2016, approximately $1 million of the $13 million restructuring charge incurred is included in other current liabilities. Additionally, we expect to incur further severance costs of less than $1 million related to this phase of our restructuring plan. The severance costs estimate could change based on the number of employees that work through the required service period and the timing of those departures.

In January 2015, we announced the initial phase of this cost reduction plan, which involved the elimination of certain corporate employee positions. As a result, we recorded employee termination costs of approximately $11 million, all of which were paid during the year ended December 31, 2015, and are included in restructuring costs within total operating costs and expenses in the consolidated statement of operations for the year ended December 31, 2015.

20. Supplemental Cash Flow Information

	Year Ended December 31,		
	2016	2015	2014
		(millions)	
Cash paid for interest, net of capitalized interest	$ 306	$ 293	$ 274
Cash paid for income taxes, net of income tax refunds received	$ 2	$ 3	$ 4
Non-cash investing and financing activities:			
Contribution from member	$ —	$ 1,500	$ —
Property, plant and equipment acquired with accrued liabilities	$ 27	$ 35	$ 145
Other non-cash changes in property, plant and equipment	$ (3)	$ (19)	$ 27

21. Subsequent Events

We have evaluated subsequent events occurring through February 17, 2017, the date the consolidated financial statements were issued.

On December 30, 2016, we entered into the Contribution Agreement with the Partnership and Operating Partnership. The Transaction closed and was effective on January 1, 2017. For additional information regarding the Transaction, see Note 6 - Agreements and Transactions with Related Parties and Affiliates.

On January 26, 2017, the Partnership announced that the board of directors of the Partnership's general partner declared a quarterly distribution of $0.78 per unit, payable on February 14, 2017 to unitholders of record on February 7, 2017, except that the owners of the Partnership's general partner will receive distributions on the units issued on January 1, 2017 beginning with the first quarter 2017 declared distribution.