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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of report (date of earliest event reported): May 24, 2017

DCP MIDSTREAM, LP
(Exact name of registrant as specified in its charter)

Delaware	**001-32678**	**03-0567133**
(State or other jurisdiction of incorporation)	**(Commission File No.)**	**(IRS Employer Identification No.)**

370 17th Street, Suite 2500
Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

(303) 595-3331
(Registrant's telephone number, including area code)

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the Registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

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

Item 8.01 Other Events.

On December 30, 2016, DCP Midstream, LP (the "Partnership") entered into a Contribution Agreement (the “Contribution Agreement”) with DCP Midstream, LLC 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 hereinafter as the “Transaction.” The Transaction closed effective January 1, 2017. As a result of this transaction, our predecessor results consist of all of the previous ownership interests that DCP Midstream, LLC held in all of its subsidiaries that owned operating assets ("The DCP Midstream Business"), which DCP Midstream, LLC contributed to us on January 1, 2017. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the relevant period, and prior years were retrospectively adjusted to furnish comparative information, similar to the pooling method. Accordingly, we have recast our consolidated financial statements to include the historical results of The DCP Midstream Business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC’s basis in the net assets contributed. The amount of the purchase price in deficit of DCP Midstream, LLC’s basis in the net assets was recognized as an addition to limited partners’ equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

Attached hereto as Exhibit 12.1 is the Computation of Ratio of Earnings to Fixed Charges for the periods presented therein, which replaces Exhibit 12.1 in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2016, which was filed with the Securities and Exchange Commission (the "SEC") on February 15, 2017 (the "2016 Form 10-K"). Attached hereto as Exhibit 99.1 is the description of our Business, which replaces Item 1 in the 2016 Form 10-K. Attached hereto as Exhibit 99.2 is the Selected Financial Data, which replaces Item 6 in the 2016 Form 10-K. Attached hereto as Exhibit 99.3 is Management’s Discussion and Analysis of Financial Condition and Results of Operations, which relates to the audited Consolidated Financial Statements of the Partnership as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015, and 2014 (the "Consolidated Financial Statements") and replaces Item 7 (but not Item 7A) in the 2016 Form 10-K. Attached hereto as Exhibit 99.4 are the Consolidated Financial Statements, which replace Item 8 in the 2016 Form 10-K. The Consolidated Financial Statements give retrospective effect to the Partnership's acquisition of The DCP Midstream Business. Attached hereto as Exhibit 99.5 is Certain Relationships and Related Transactions, and Director Independence, which replaces Item 13 in the 2016 Form 10-K. Attached hereto as Exhibit 101 is the information included in Exhibit 99.4, formatted in XBRL, which replaces Exhibit 101 in the 2016 Annual Report on Form 10-K.

Except as otherwise expressly noted above, this Current Report on Form 8-K does not supersede any other information set forth in the 2016 Form 10-K and should be read in conjunction with the 2016 Form 10-K and our other filings with the SEC.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	**Description**
12.1	Computation of Ratio of Earnings to Fixed Charges.
23.1	Consent of Deloitte & Touche LLP.
99.1	Business.
99.2	Selected Financial Data.
99.3	Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.4	Financial Statements and Supplementary Data.
99.5	Certain Relationships and Related Transactions, and Director Independence.
101	Financial statements of DCP Midstream, LP for the year ended December 31, 2016, formatted in XBRL: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows,and (vi) the Notes to the Consolidated Financial Statements.

SIGNATURE

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

Date: May 24, 2017

DCP MIDSTREAM, LP

By: **DCP MIDSTREAM GP, LP**
its General Partner

By: **DCP MIDSTREAM GP, LLC**
its General Partner

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

EXHIBIT INDEX

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Exhibit 12.1

DCP Midstream, LP
Computation of Ratio of Earnings to Fixed Charges

The table below sets forth the computation of Ratio of Earnings to Fixed Charges:

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

(a) The financial information for the years ended December 31, 2016, 2015, 2014, 2013 and 2012 includes the results of The DCP Midstream Business, which was acquired from DCP Midstream, LLC on January 1, 2017. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.
(b) Earnings for the year ended December 31, 2015 were inadequate to cover fixed charges by $998 million.

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

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-142271 and 333-211905 on Form S-8 and Registration Statement Nos. 333-182642, 333-196939 and 333-203588 on Form S-3 of our report dated February 15, 2017 (May 24, 2017 as to Notes 1, 4 and 25), relating to the consolidated financial statements of DCP Midstream, LP and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph referring to the retrospective adjustment for the acquisition of 100% of the ownership interest in the DCP Midstream Business, from DCP Midstream, LLC on January 1, 2017, which has been accounted for in a manner similar to a pooling of interests) appearing in this Current Report on Form 8-K of DCP Midstream, LP dated May 24, 2017.

/s/ Deloitte & Touche LLP

Denver, Colorado
May 24, 2017

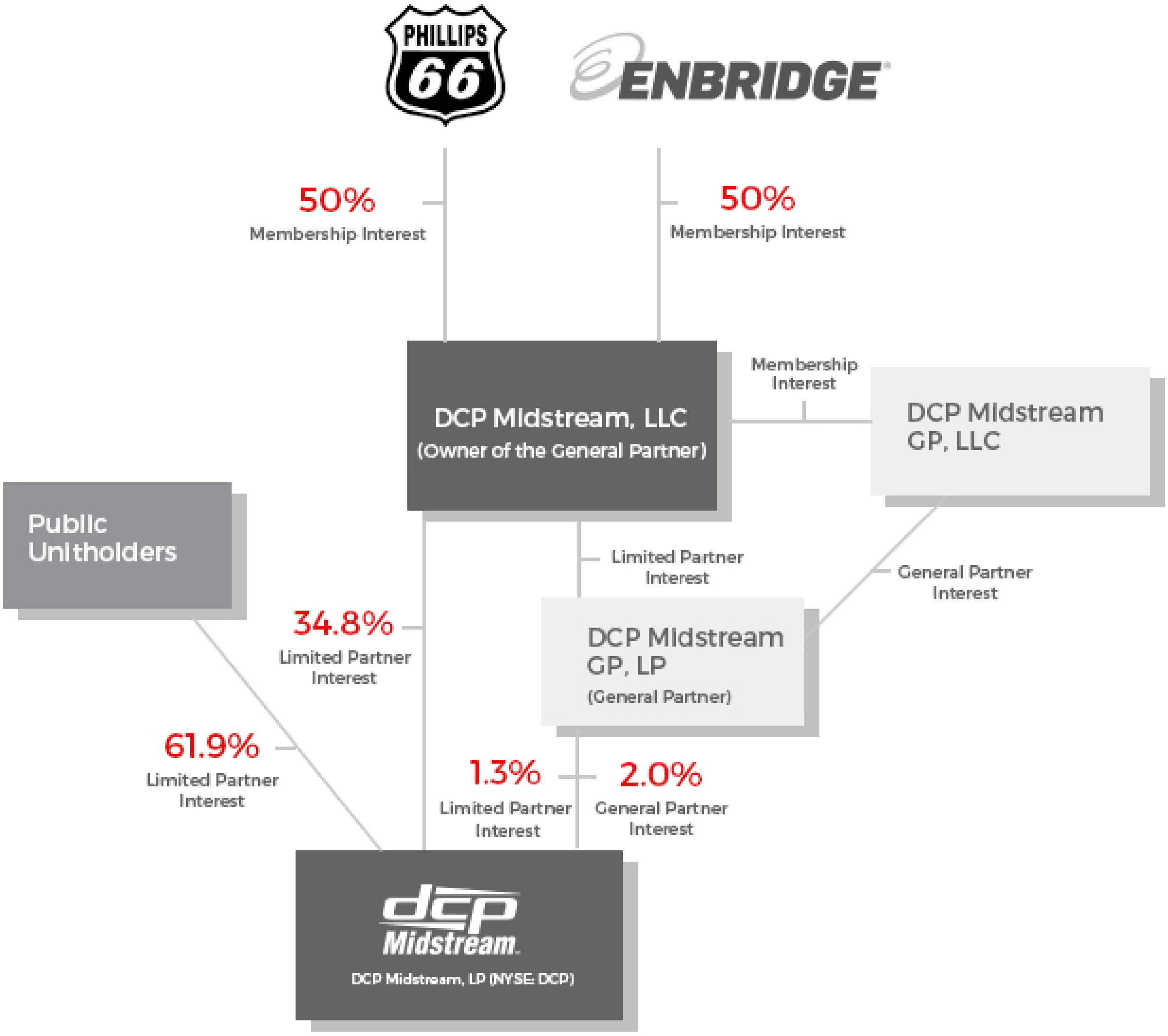
Exhibit 99.1

Item 1. ***Business***

OVERVIEW

DCP Midstream, LP (together with its consolidated subsidiaries, “we”, “our”, “us”, the “registrant”, or the “Partnership”) is a Delaware limited Partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC is owned 50% by Phillips 66 and 50% by Enbridge, Inc. and its affiliates, or Enbridge.

The diagram below depicts our organizational structure as of May 24, 2017.



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

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

OUR BUSINESS STRATEGY

Our primary business objectives are to achieve sustained company profitability, a strong balance sheet and profitable growth, thereby sustaining our cash distribution per unit. We intend to accomplish these objectives by prudently executing the following business strategies:

Operational Performance. We believe our operating efficiency and reliability enhance our ability to attract new natural gas supplies by enabling us to offer more competitive terms, services and service flexibility to producers. Our gathering and processing systems and logistics assets consist of high-quality, well-maintained facilities, resulting in low-cost, efficient operations. Our goal is to establish a reputation in the midstream industry as a reliable, safe and low cost supplier of services to our customers. We will continue to pursue new contracts, cost efficiencies and operating improvements of our assets. We seek to increase the utilization of our existing facilities by providing additional services to our existing customers and by establishing relationships with new customers. In addition, we maximize efficiency by coordinating the completion of new facilities in a manner that is consistent with the expected production that supports them.

Organic Growth. We intend to use our strategic asset base in the United States and our position as the largest gatherer of natural gas, and as one of the largest producers and marketers of NGLs in the United States, as a platform for future growth. We plan to grow our business by constructing new gathering lines, processing facilities and NGL pipeline infrastructure, and expanding existing infrastructure.

Strategic Acquisitions and Partnerships. We intend to pursue economically attractive and strategic acquisition and partnership opportunities within the midstream energy industry, both in new and existing lines of business, and areas of operation.

OUR COMPETITIVE STRENGTHS

We are the largest gatherer of natural gas, based on wellhead volumes, in the United States, and one of the largest producers and marketers of NGLs in the United States. In 2016, our total wellhead volume was approximately 5.1 Bcf/d of natural gas and we produced an average of approximately 393 MBbls/d of NGLs. We provide an integrated package of logistics and marketing services to producers. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide substantially all services to move natural gas and NGLs from wellhead to market and creates value for our customers. We believe that we are well positioned to execute our business strategies and achieve one of our primary business objectives of sustaining our cash distribution per unit because of the following competitive strengths:

Strategically Located Gas Gathering and Processing Operations. Our assets are strategically located in areas with the potential for increasing our wellhead volumes and cash flow generation. We have operations in some of the largest producing regions in the United States: Permian Basin, Denver-Julesburg Basin ("DJ Basin"), Midcontinent, and Eagle Ford. In addition, we operate one of the largest portfolios of natural gas processing plants in the United States. Our gathering systems and processing plants are connected to numerous key natural gas pipeline systems that provide producers with access to a variety of natural gas market hubs.

Integrated Logistics and Marketing Operations. We have connected our gathering and processing operations to key markets with NGL pipelines that offer our customers a competitive, integrated midstream service. We have strategically located NGL transportation pipelines in the Midcontinent, DJ Basin, East Texas, Gulf Coast, South Texas, Central Texas, and Permian Basin which are major NGL producing regions, NGL fractionation facilities in the Gulf Coast and an NGL storage facility in Michigan. Our NGL pipelines connect to various natural gas processing plants and transport the NGLs to large fractionation facilities, a petrochemical plant, a third party underground NGL storage facility and other markets along the Gulf Coast. Our NGL storage facility in Michigan is strategically adjacent to the Sarnia, Canada refinery and petrochemical corridor. We also have residue gas storage capacity at our Spindletop natural gas storage facility. We believe the strategic location of our assets coupled with their geographic diversity and our reputation for running our business reliably and effectively, presents us with continuing opportunities to provide competitive services to our customers and attract new natural gas production.

Stable Cash Flows. Our operations consist of a mix of fee-based and commodity-based services, which together with our commodity hedging program, are intended to generate relatively stable cash flows. Growth in our fee-based earnings will reduce the impact of unhedged margins. Additionally, while certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a portion of our currently anticipated commodity price risk associated with the equity volumes from our gathering and processing operations with fixed price commodity swaps, settling through the first quarter of 2018.

Established Relationships with Oil, Natural Gas and Petrochemical Companies. We have long-term relationships with many of our suppliers and customers, and we expect that we will continue to benefit from these relationships.

Experienced Management Team. Our senior management team and board of directors have extensive experience in the midstream industry. We believe our management team has a proven track record of enhancing value through organic growth and the acquisition, optimization and integration of midstream assets.

Affiliation with DCP Midstream, LLC and its owners. Our relationship with DCP Midstream, LLC and its owners, Phillips 66 and Enbridge, should continue to provide us with significant business opportunities. Through our relationship with DCP Midstream, LLC and its owners, we believe our strong commercial relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate the implementation of our strategies.

DCP Midstream, LLC has a significant interest in us through its ownership of an approximately 2% general partner interest, a 36% limited partner interest and all of our incentive distribution rights.

OUR OPERATING SEGMENTS

Gathering and Processing Segment

General

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

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

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

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

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

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

We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps to mitigate a portion of our commodity price exposure to NGLs.

During 2016, total wellhead volume on our assets was approximately 5.1 Bcf/d, originating from a diversified mix of customers. Our systems each have significant customer acreage dedications that will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and also by contracting with undedicated producers who are operating in or around our gathering footprint. During 2016, the combined NGL production from our processing facilities was approximately 393 MBbls/d and was delivered and sold into various NGL takeaway pipelines.

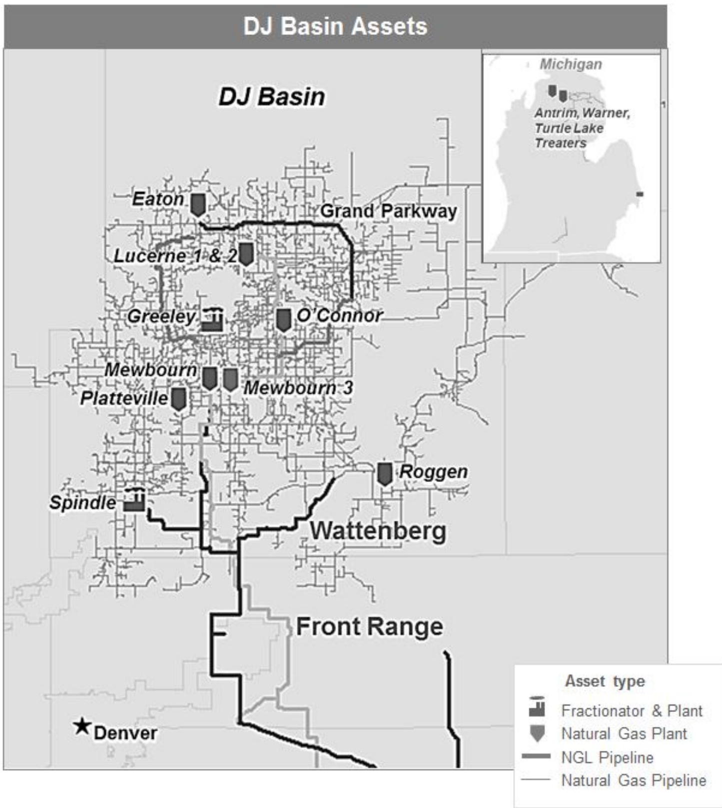
The following is operating data for our Gathering and Processing segment by region:

Operating Data

				Year Ended December 31, 2016	
Regions	Plants	Approximate Gathering and Transmission Systems (Miles)	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Natural Gas Wellhead Volume (MMcf/d) (a)	NGL Production (MBbls/d) (a)
North	13	5,445	1,255	1,126	82
Permian	16	16,300	1,460	1,041	107
Midcontinent	12	29,420	1,765	1,269	94
South	20	7,415	3,295	1,688	110
Total	61	58,580	7,775	5,124	393

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

North Region

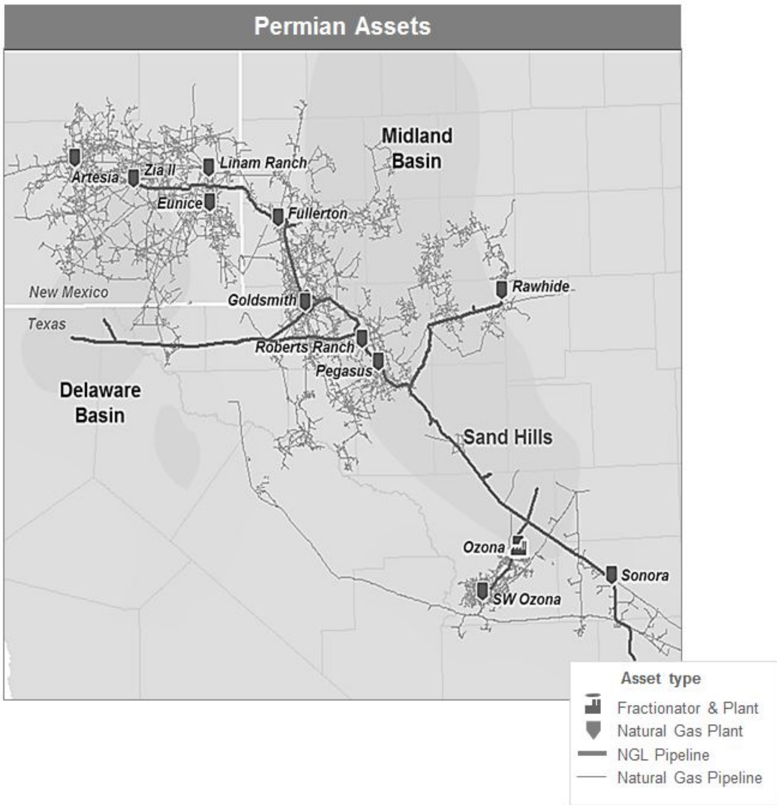


Our North region primarily consists of our DJ Basin system. We have a broad network of gathering and processing facilities in Weld County, Colorado that provide significant optionality and flexibility.

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

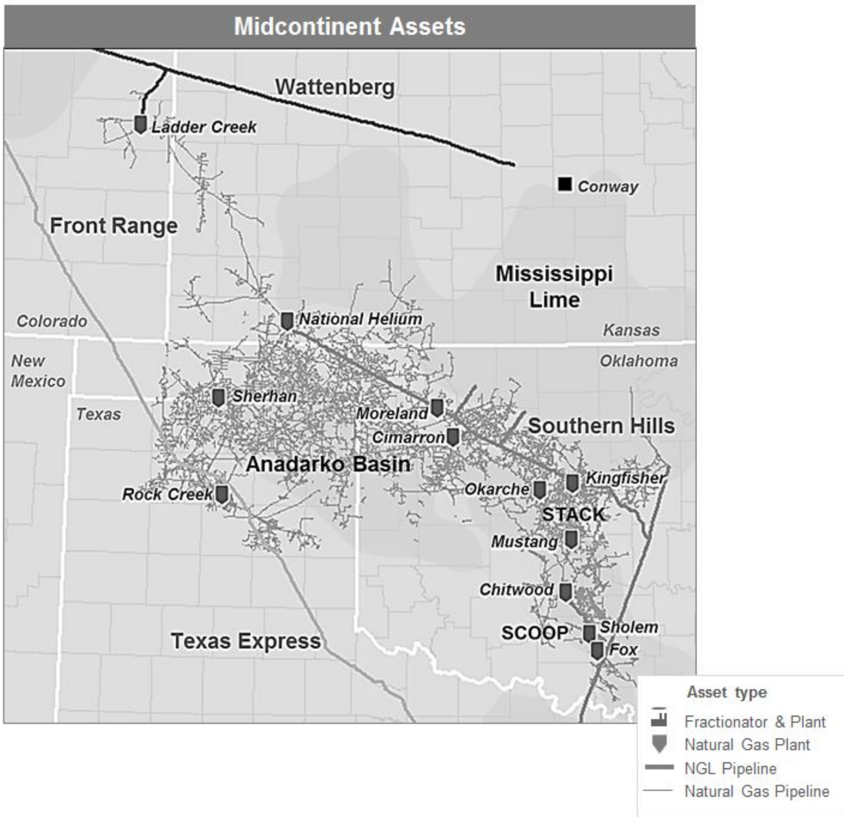
Our DJ Basin system delivers to the Mont Belvieu hub in Mont Belvieu, Texas via the Front Range and Texas Express pipelines, owned 33.33% and 10% by us, respectively, and to the Conway hub in Bushton, Kansas via our Wattenberg pipeline in our Logistics and Marketing segment.

Permian Region



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

Midcontinent Region

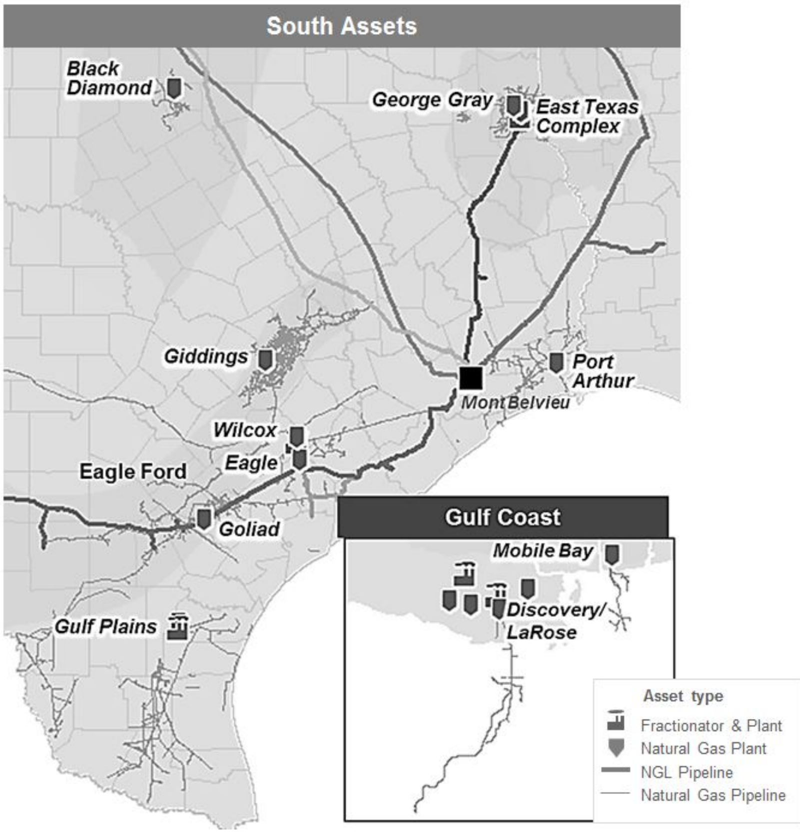


Our Midcontinent region primarily includes our Liberal system, Panhandle system, and our Central Oklahoma system. We gather and process raw natural gas primarily from the Ardmore and Anadarko Basins, including the prolific South Central Oklahoma Oil Province (“SCOOP”) play and the Sooner Trend Anadarko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

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

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

South Region



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

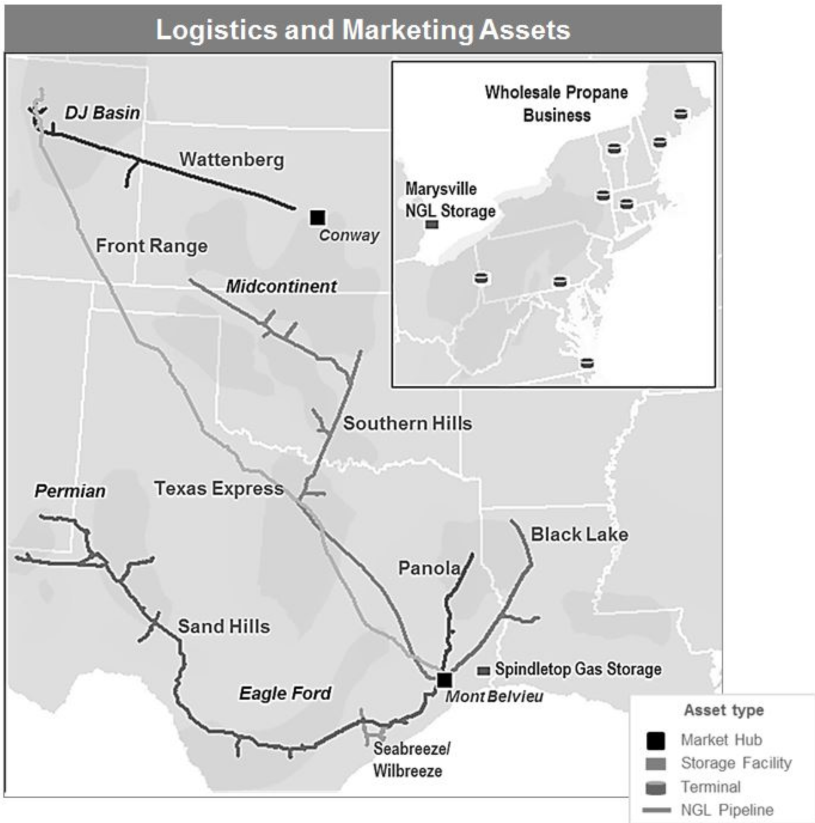
Our Eagle Ford system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through our Sand Hills pipeline and other third party NGL pipelines. Our East Texas system provides NGL takeaway service through the Panola pipeline, owned 15% by us, and delivers gas primarily through its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

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

Competition

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

Logistics and Marketing Segment



General

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

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

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

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

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

The following is operating data for our Logistics and Marketing segment:

Operating Data

						Year Ended December 31, 2016	
System	**Approximate System Length (Miles)**	**Fractionators**	**Approximate Throughput Capacity (MBbls/d) (a)**	**Approximate NGL Storage Capacity (MMBbls)**	**Approximate Natural Gas Storage Capacity (Bcf)**	**Pipeline Throughput (MBbls/d) (a)**	**Fractionator Throughput (MBbls/d) (a)**
Sand Hills pipeline	1,325	—	186	—	—	158	—
Southern Hills pipeline	940	—	117	—	—	65	—
Front Range pipeline	450	—	50	—	—	34	—
Texas Express pipeline	595	—	28	—	—	15	—
Other pipelines	2,480	—	172	—	—	148	—
Mont Belvieu fractionators	—	2	60	—	—	—	50
Storage facilities	—	—	—	8	12	—	—
Total	5,790	2	613	8	12	420	50

(a) Represents total NGL capacity or throughput allocated to our proportionate ownership share for 2016 divided by 365 days.

NGL Pipelines

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

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

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

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

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

NGL Fractionation Facilities

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

Storage Facilities

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

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

Wholesale Propane

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

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

Trading and Marketing

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

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period 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.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. As discussed above, the accounting for physical gas purchases and sales and the accounting for the derivative instruments used to manage such purchases and sales differ, and may subject our earnings to market volatility, even though the transaction represents an economic hedge in which we have locked in a future margin.

Customers and Contracts

We sell NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small regional retail propane distributors. Substantially all of our NGL sales are made at market-based prices, including approximately 27% of our NGL production which was committed to Phillips 66 and Chevron Phillips Chemical, or CPChem as of December 31, 2016. The primary production commitment on certain contracts began a ratable wind down period in December 2014 and expires in January 2019. We anticipate continuing to purchase and sell commodities with Phillips 66 and CPChem in the ordinary course of business.

Competition

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

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

Other Segment Information

For additional information on our segments, please see Exhibit 99.3 “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and Note 21 of the Notes to Consolidated Financial Statements in Exhibit 99.4 “Financial Statements and Supplementary Data" in this Form 8-K.

We have no revenue attributable to international activities.

REGULATORY AND ENVIRONMENTAL MATTERS

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA applies to interstate and intrastate pipeline facilities and the pipeline transportation of liquid petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines in high-consequence areas within 10 years. DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, (the Pipeline Safety and Job Creations Act) reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by DOT's PHMSA address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

The Pipeline Safety and Job Creation Act requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The legislation gives PHMSA civil penalty authority up to $200,000 per day per violation, with a maximum of $2 million for any related series of violations. Any material penalties or fines under these or other statutes, rules, regulations or orders could have a material adverse impact on our business, financial condition, results of operation and cash flows.

We currently estimate we will incur between $16 million and $20 million between 2017 and 2021 to implement integrity management program testing along certain segments of our natural gas transmission and NGL pipelines. We believe that we are in compliance in all material respects with the NGPSA and the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety and Job Creation Act.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate. Our natural gas transmission and regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management and EPA Risk Management Program regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The OSHA regulations apply to any process which involves a chemical at or above specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells holding or handling these materials in quantities in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt from these standards. The EPA regulations have similar applicability thresholds. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to worker health and safety.

Propane Regulation

National Fire Protection Association Codes No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the DOT. The transportation of propane by rail is regulated by the Federal Railroad Administration. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

FERC and State Regulation of Operations

FERC regulation of interstate natural gas pipelines, the marketing and sale of natural gas in interstate commerce and the transportation of NGLs in interstate commerce may affect certain aspects of our business and the market for our products and services. Regulation of gathering systems and intrastate transportation of natural gas and NGLs by state agencies may also affect our business.

Interstate Natural Gas Pipeline Regulation

Our Cimarron River, Discovery, and Dauphin Island Gathering Partners systems, or portions thereof, are some of our natural gas pipeline assets that are subject to regulation by FERC, under the Natural Gas Act of 1938, as amended, or NGA. Natural gas companies subject to the NGA may only charge rates that have been determined to be just and reasonable. In addition, FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of transportation services;
- terms and conditions of transportation services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

Generally, the maximum filed recourse rates for an interstate natural gas pipeline's transportation services are based on the pipeline's cost of service including recovery of and a return on the pipeline’s actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, including an income tax allowance, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The allocation of costs to various pipeline services and the manner in which rates are designed also can impact a pipeline's profitability. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline’s FERC-approved gas tariff. FERC-regulated natural gas pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the minimum rate or variable cost of performing service, provided they do not “unduly discriminate.”

Tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If FERC determines, as required by the NGA, that a proposed change is just and reasonable, FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if FERC determines that a proposed change may not be just and reasonable as required by NGA, then FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint, initiate a proceeding to compel the company to change or justify its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by FERC and Congress, especially in light of potential market power abuse by marketing companies engaged in interstate commerce. In the Energy Policy Act of 2005, or EPACT 2005, Congress amended the NGA and Federal Power Act to add anti-fraud and anti-manipulation requirements. EPACT 2005 prohibits the use of any “manipulative or deceptive device or contrivance” in connection with the purchase or sale of natural gas, electric energy or transportation subject to FERC jurisdiction. FERC adopted market manipulation and market behavior rules to implement the authority granted under EPACT 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are subject to broad interpretation. Given FERC's broad mandate granted in EPACT 2005, if energy prices are high, or exhibit what FERC deems to be "unusual" trading patterns, FERC may investigate energy markets to determine if behavior unduly impacted or "manipulated" energy prices.

In addition, EPACT 2005 gave FERC increased penalty authority for violations of the NGA and FERC's rules and regulations thereunder. FERC may issue civil penalties of up to $1 million per day per violation, and violators may be subject to criminal penalties of up to $1 million per violation and five years in prison. FERC may also order disgorgement of profits obtained in violation of FERC rules. FERC relies on its enforcement authority in issuing a number of natural gas enforcement actions. Failure to comply with the NGA and FERC's rules and regulations thereunder could result in the imposition of civil penalties and disgorgement of profits.

Intrastate Natural Gas Pipeline Regulation

Intrastate natural gas pipeline operations are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate gas pipelines to provide service that is not unduly discriminatory and to file and/or seek approval of their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. For example, our Guadalupe system is an intrastate pipeline regulated as a gas utility by the Railroad Commission of Texas. To the extent that an intrastate pipeline system transports natural gas in interstate commerce, the rates and terms and conditions of such interstate transportation service are subject to FERC rules and regulations under Section 311 of the Natural Gas Policy Act, or NGPA. Certain of our systems are subject to FERC jurisdiction under Section 311 of the NGPA for their interstate transportation services. Section 311 regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. Additionally, the terms and conditions of service set forth in the intrastate pipeline’s Statement of Operating Conditions are subject to FERC approval. Non-compliance with FERC's rules and regulations established under Section 311 of the NGPA, including failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline’s FERC-approved Statement of Operating Conditions could result in the imposition of civil and criminal penalties. Among other matters, EPACT 2005 also amended the NGPA to give FERC authority to impose civil penalties for violations of the NGPA up to $1 million for any one violation and violators may be subject to criminal penalties of up to $1 million per violation and five years in prison.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We believe that our natural gas gathering facilities meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services continues to be a current issue in various FERC proceedings with respect to facilities that interconnect gathering and processing plants with nearby interstate pipelines, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental, and, in many circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels where FERC has recognized a jurisdictional exemption for the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our interstate purchases and sales of natural gas, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or CFTC. Should we violate the anti-market manipulation laws and regulations, in additional to civil and criminal penalties, we could be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Interstate NGL Pipeline Regulation

Certain of our pipelines, including Sand Hills and Southern Hills, are common carriers that provide interstate NGL transportation services subject to FERC regulation. FERC regulates interstate common carriers under its Oil Pipeline Regulations, the Interstate Commerce Act of 1887, as amended, or ICA, and the Elkins Act of 1903, as amended. FERC requires that common carriers file tariffs containing all the rates, charges and other terms for services provided by such pipelines. The ICA requires that tariffs apply to the interstate movement of NGLs, as is the case with the Sand Hills, Southern Hills, Black Lake, Wattenberg and Front Range pipelines. Pursuant to the ICA, rates must be just, reasonable, and nondiscriminatory, and can be challenged at FERC either by protest when they are initially filed or increased or by complaint at any time they remain on file with FERC.

In October 1992, Congress passed EPACT, which among other things, required FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. FERC responded to this mandate by issuing several orders, including Order No. 561 that enables petroleum pipelines to charge rates up to their ceiling levels, which are adjusted annually based on an inflation index. Specifically, the indexing methodology requires a pipeline to adjust the ceiling level for its rates annually by the inflation index established by the FERC. FERC reviews the indexing methodology every five years, and in 2015, the indexing methodology for the five years beginning July 1, 2016 was changed to be the Producer Price Index for Finished Goods plus 1.23 percent. The previous five-year period utilized the Producer Price Index for Finished Goods plus 2.65 percent. Pipelines may charge up to the calculated ceiling level for their transportation rates, and typically adjust their rates July 1 annually, when the new inflation index and ceiling levels are calculated. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline’s increase in costs from the previous year. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline’s filed rate, the pipeline is required to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate “grandfathered” under EPACT (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. Because of the change in indexing methodology effective July 1, 2016 and the trends in the producer price index, the ceiling levels calculated for our interstate NGL pipelines may be subject to decrease, which occurred in 2016 and resulted in the decrease in the tariff rates for many such pipelines.

EPACT deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPACT that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the ICA. Generally, complaints against such “grandfathered” rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPACT in either the economic circumstances of the petroleum pipeline, or in the nature of the services provided, that were a basis for the rate. EPACT places no such limit on challenges to a provision of a petroleum pipeline tariff as unduly discriminatory or preferential.

On October 20, 2016, FERC issued an Advance Notice of Proposed Rulemaking, which presented significant changes to the indexing mechanism and reporting requirements of common carriers subject to FERC's jurisdiction under the ICA. The proposed changes to the indexing methodology, would prohibit an increase in a common carrier's ceiling level and rates if a complaint was filed and the return as reported by the common carrier in two previous annual reports exceeded a predetermined threshold. Additionally, the FERC proposed multiple changes to its annual reporting requirements. We cannot predict the outcome of the proceeding, but the proposal, if implemented, could adversely impact future rate increases of our common carriers and place additional administration and reporting burdens on our business.

Intrastate NGL Pipeline Regulation

NGL and other common carrier petroleum pipelines that provide intrastate transportation services are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file tariffs and their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. For example, certain of our pipelines have tariffs filed with the Railroad Commission of Texas for their intrastate NGL transportation services.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, compressing, treating, processing, transporting, fractionating, storing or selling natural gas, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the emission or discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the acquisition of permits or authorizations to conduct regulated activities and imposing obligations in those permits, potentially including capital expenditures or operational requirements, that reduce or limit impacts to the environment;
- restricting the ways that we can handle or dispose of our wastes;
- limiting or prohibiting construction or operational activities in sensitive areas such as wetlands, coastal regions or areas inhabited by threatened and endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining, or compelling changes to, the operations of facilities deemed not to be in compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil, or potentially criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, potential citizen lawsuits, and the issuance of orders enjoining or affecting future operations. Certain environmental statutes impose strict liability or joint and several liability for costs required to clean up and restore sites where hazardous substances, or in some cases hydrocarbons, have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for property damage or personal injury allegedly caused by the release of substances or other waste products into the environment.

The overall trend in federal and state environmental programs is to expand regulatory requirements, placing more restrictions and limitations on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations, participate as applicable in the public process to ensure such new requirements are well founded and reasonable or to revise them if they are not, and to manage the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. Below is a discussion of the more significant environmental laws and regulations that relate to our business.

Impact of Air Quality Standards and Climate Change

A number of states have adopted or considered programs to reduce "greenhouse gases," or GHGs, which can include methane, and, depending on the particular program or jurisdiction, we could be required to purchase and surrender allowances, either for GHG emissions resulting from our operations (*e.g.*, compressor units) or from downstream combustion of fuels (*e.g.*, oil or natural gas) that we process, or we may otherwise be required by regulation to take steps to reduce emissions of GHGs. Also, the EPA has declared that GHGs "endanger" public health and welfare, and is regulating GHG emissions from mobile sources such as cars and trucks. The EPA's 2010 action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, particularly the Prevention of Significant Deterioration program and Title V permitting. These requirements for stationary sources took effect on January 2, 2011; however, in June 2014 the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA's greenhouse gas permitting rules to the extent they impose a requirement to obtain a federal air permit based solely on emissions of greenhouse gases, but major sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. The EPA proposed a rule in 2016 to comply with the U.S. Supreme Court's ruling by limiting the requirement to obtain permits addressing emissions of greenhouse gases to large sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, which also emit 100,000 tons per year or more of CO_2 equivalent (or modifications of these sources that result in an emissions increase of 75,000 tons per year or more of CO_2). The EPA has also published various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems. In October 2015, the EPA amended and expanded greenhouse gas reporting requirements to all segments of the oil and gas sector starting with the 2016 reporting year. In June 2016, the EPA published final new source performance standards for methane (a greenhouse gas) from new and modified oil and gas sector sources. These regulations expand upon the 2012 EPA rulemaking for oil and gas equipment-specific emissions controls, for example, regulating well head production emissions with leak detection and repair requirements, pneumatic controllers and pumps requirements, compressor requirements, and instituting leak detection and repair requirements for natural gas compressor and booster stations for the first time. In October 2015, the EPA finalized a reduction of the ambient ozone standard from 75 parts per billion to 70 parts per billion under the Clean Air Act. The EPA also finalized in October 2016 Control Techniques Guidelines for emissions of volatile organic compounds from oil and gas sector sources to be implemented or utilized by states in ozone nonattainment areas, with an expected co-benefit of reduced methane emissions. The permitting, regulatory compliance and reporting programs, taken as a whole, increase the costs and complexity of oil and gas operations with potential to adversely affect the cost of doing business for our customers resulting in reduced demand for our gas processing and transportation services, and which may also require us to incur certain capital and operating expenditures in the future to meet regulatory requirements or for air pollution control equipment, for example, in connection with obtaining and maintaining operating permits and approvals for air emissions associated with our facilities and operations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, or solid or hazardous wastes, including petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict liability or joint and several liability for the investigation and remediation of areas at a facility where hazardous substances, or in some cases hydrocarbons, may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible parties the costs that the agency incurs. Despite the "petroleum exclusion" of CERCLA Section 101(14), which encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum and natural gas production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, may in the future be designated by the EPA as hazardous wastes and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where petroleum hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under the other locations where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed or released thereon may be subject to CERCLA, RCRA and analogous state laws, or separate state laws that address hydrocarbon releases. Under these laws, we could be required to remove or remediate releases of hydrocarbon materials, or previously disposed wastes (including wastes disposed of or released by prior owners or operators), or to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our operations or financial condition.

Water

The Federal Water Pollution Control Act of 1972, as amended, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA also requires implementation of spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of threshold quantities of oil or certain other materials. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. The EPA has also promulgated regulations that require us to have permits in order to discharge certain storm water. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water discharges. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

The Oil Pollution Act of 1990, or OPA, which is part of the Clean Water Act, addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities, including natural gas gathering and processing facilities, terminals, pipelines, and transfer facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in government penalties and civil liability. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our operations or financial condition.

Anti-Terrorism Measures

The federal Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present "high levels of security risk." Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory provisions, including requirements regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

Employees

We do not have any employees. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which is managed by its general partner, DCP Midstream GP, LLC, or the General Partner, which is 100% owned by DCP Midstream, LLC. Approximately 2,650 employees of DCP Services, LLC, a wholly-owned subsidiary of DCP Midstream, LLC, provided support for our operations pursuant to the Services and Employee Secondment Agreement between DCP Services, LLC and us. For additional information, refer to “Item 10. Directors, Executive Officers and Corporate Governance” in our Annual Report on Form 10-K filed with the SEC on February 15, 2017 (the "2016 Form 10-K) and Exhibit 99.5 “Certain Relationships and Related Transactions, and Director Independence - Services Agreement” in this Form 8-K.

General

We make certain filings with the Securities and Exchange Commission, or SEC, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports, which are available free of charge through our website, *www.dcpmidstream.com*, as soon as reasonably practicable after they are filed with the SEC. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report. The filings are also available through the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at *www.sec.gov*. Our annual reports to unitholders, press releases and recent analyst presentations are also available on our website. We have also posted our code of business ethics on our website.

Exhibit 99.2

Selected Financial Data

The following table shows our selected financial data for the periods and as of the dates indicated, which is derived from our consolidated financial statements. These consolidated financial statements consist of all of the ownership interests of DCP Midstream, LLC in all of its subsidiaries that owned operating assets ("The DCP Midstream Business"), which we acquired from DCP Midstream, LLC on January 1, 2017. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information, similar to the pooling method. Accordingly, our consolidated financial statements include the historical results of The DCP Midstream Business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. The amount of the purchase price in deficit of DCP Midstream, LLC's basis in the net assets is recognized as an addition to limited partners' equity. The information contained herein should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Form 8-K.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial condition or results of operations. The table should be read together with Exhibit 99.3 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Form 8-K, which includes our critical accounting estimates.

The following table shows our selected financial and operating data for the periods and as of the dates indicated, which is derived from our consolidated financial statements.

	Year Ended December 31,				
	2016	2015	2014	2013	2012 (a)
	(Millions, except per unit amounts)				
Statements of Operations Data:					
Sales of natural gas, NGLs and condensate	$ 6,269	$ 6,779	$ 13,420	$ 11,539	$ 9,712
Transportation, processing and other	647	532	517	463	373
Trading and marketing (losses) gains, net	(23)	119	88	36	86
Total operating revenues	6,893	7,430	14,025	12,038	10,171
Operating costs and expenses:					
Purchases of natural gas and NGLs	5,461	5,981	11,828	9,967	8,172
Operating and maintenance expense	670	732	773	691	667
Depreciation and amortization expense	378	377	348	314	291
General and administrative expense	292	281	277	280	297
Asset impairments	—	912	18	—	—
Other (income) expense, net	(65)	10	7	—	—
(Gain) loss on sale of assets, net	(35)	(42)	7	(22)	—
Restructuring costs	13	11	—	—	—
Total operating costs and expenses	6,714	8,262	13,258	11,230	9,427
Operating income (loss)	179	(832)	767	808	744
Interest expense, net	(321)	(320)	(287)	(249)	(193)
Earnings from unconsolidated affiliates (b)	282	184	82	35	34
Income (loss) before income taxes	140	(968)	562	594	585
Income tax benefit (expense) benefit	(46)	102	(11)	(10)	(2)
Net income (loss)	94	(866)	551	584	583
Net income attributable to non-controlling interests	(6)	(5)	(4)	(5)	(5)
Net income (loss) attributable to partners	88	(871)	547	579	578
Net loss (income) attributable to predecessor operations (c)	224	1,099	(130)	(404)	(413)
General partner interest in net income	(124)	(124)	(114)	(70)	(41)
Net income allocable to limited partners	$ 188	$ 104	$ 303	$ 105	$ 124
Net income per limited partner unit-basic and diluted	$ 1.64	$ 0.91	$ 2.84	$ 1.34	$ 2.28

	Year Ended December 31,				
	2016	2015	2014	2013	2012 (a)
	(Millions, except per unit amounts)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 9,069	$ 9,428	$ 9,537	$ 8,420	$ 7,331
Total assets	$ 13,611	$ 13,885	$ 13,628	$ 12,684	$ 10,749
Accounts payable	$ 735	$ 545	$ 977	$ 1,413	$ 1,153
Long-term debt	$ 4,907	$ 5,669	$ 5,191	$ 4,925	$ 4,408
Partners’ equity	$ 2,601	$ 2,772	$ 2,993	$ 1,945	$ 1,405
Predecessor equity	$ 4,220	$ 4,287	$ 2,189	$ 2,410	$ 1,877
Non-controlling interests	$ 32	$ 33	$ 33	$ 34	$ 35
Total equity	$ 6,853	$ 7,092	$ 5,215	$ 4,389	$ 3,317
Other Information:					
Cash distributions declared per unit	$ 3.1200	$ 3.1200	$ 3.0525	$ 2.8630	$ 2.7000
Cash distributions paid per unit	$ 3.1200	$ 3.1200	$ 3.0050	$ 2.8200	$ 2.6600

(a) Includes the effect of the following acquisitions prospectively from their respective dates of acquisition: (1) a 10% ownership interest in the Texas Express Pipeline acquired from Enterprise Products Partners, L.P. in April 2012; and (2) the Crossroads processing plant and 50% interest in CrossPoint Pipeline, LLC, acquired from Penn Virginia Resource Partners, L.P. in July 2012.

(b) Includes our proportionate share of the earnings of our unconsolidated affiliates. Earnings include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

(c) Includes net (loss) income attributable to The DCP Midstream Business prior to the date of our acquisition from DCP Midstream, LLC.

Exhibit 99.3

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this Form 8-K (and related exhibits).

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Concurrent with the completion of the Transaction in the first quarter of 2017 as defined below, management reevaluated our reportable segments and determined that our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Segment information for earlier periods has been retrospectively adjusted to reflect these reportable segments. Our Gathering and Processing reportable segment includes operating segments that have been aggregated based on the nature of the products and services provided. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering and selling condensate. Our Logistics and Marketing segment includes transporting, trading, marketing and storing natural gas and NGLs, fractionating NGLs and wholesale propane logistics. The remainder of our business operations is presented as "Other", and consists of unallocated corporate costs.

Our business is impacted by commodity prices and volumes. We mitigate a portion of commodity price risk on an overall partnership basis by growing our fee based assets and by executing on our hedging program, where we hedge commodity prices associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing segment. Various factors impact both commodity prices and volumes, and as indicated in Item 7A in our 2016 Form 10-K, "Quantitative and Qualitative Disclosures about Market Risk," we have sensitivities to certain cash and non-cash changes in commodity prices. If commodity prices weaken for a sustained period, our volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area; we will continue to target our strategy in geographic areas where we expect producer drilling activity.

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

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

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

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

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

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

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

Some of our growth projects include the following:

- Within our Logistics and Marketing segment, the Sand Hills pipeline mainline capacity expansion was placed into service during the second quarter of 2016. We are currently further expanding the Sand Hills pipeline to 365 MBbls/d expected to be in service in the fourth quarter of 2017, and have multiple additional Sand Hills lateral connections in flight throughout 2017.

- Within our Gathering and Processing segment, the construction of a 200 MMcf/d cryogenic natural gas processing plant, Mewbourn 3 plant, and further expansion of our Grand Parkway gathering system, both of which are located in the DJ Basin and expected to be in service in the fourth quarter of 2018.

- On February 1, 2016, we began to participate in earnings for our 15% interest in the Panola intrastate NGL pipeline which completed an expansion in the third quarter of 2016 and is included in our Logistics and Marketing segment.

- In the first quarter of 2016, we completed construction on our Grand Parkway gathering system in the DJ Basin, which is in our Gathering and Processing segment.

As part of our ongoing effort to create efficiencies, reduce costs and transform our business, DCP Midstream, LLC, announced an approximate 10 percent headcount reduction in April 2016, which involved the elimination of certain operational and corporate positions. This has not impacted the operation of our assets.

On April 28, 2016, the unitholders of the Partnership approved the DCP Midstream Partners, LP 2016 Long-Term Incentive Plan (the “2016 LTIP”), which replaced the 2005 long-term incentive plan that expired pursuant to its terms at the end of 2015 (the “2005 LTIP”). Any outstanding awards under the 2005 plan will remain outstanding and settle according to the terms of such grant. The 2016 LTIP 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. We believe the 2016 LTIP is an important tool to attract and retain qualified individuals who are essential to the future success of the Partnership.

Recent Events

On May 17, 2017, we announced the planned divestiture of our Douglas gathering system in Wyoming, which includes approximately 1,500 miles of gathering lines for approximately $128 million, subject to customary closing adjustments. The transaction is expected to close on or before the end of the second quarter. The proceeds from this transaction will be used to fund our strategic organic growth projects around our premier footprint, such as potential expansions of the Sand Hills NGL pipeline in the Permian and additional processing capacity and gathering systems in the DJ Basin.

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

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

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

On January 26, 2017, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit. The distribution was paid on February 14, 2017 to unitholders of record on February 7, 2017, except that the owners of the Partnership's General Partner received distributions on the units issued on January 1, 2017 beginning with the first quarter 2017 declared distribution.

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

General Trends and Outlook

During 2017, our strategic objectives will continue to focus on maintaining stable Distributable Cash Flows from our existing assets and executing on opportunities to sustain our long-term Distributable Cash Flows in light of the significant changes to our business resulting from the Transaction. We believe the key elements to stable Distributable Cash Flows are the diversity of our asset portfolio, our fee-based business which represents a significant portion of our estimated margins, plus our hedged commodity position, the objective of which is to protect against downside risk in our Distributable Cash Flows.

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

We anticipate our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Commodity Price Environment - Our business is impacted by commodity prices. If commodity prices weaken for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area; we have observed decreases in drilling activity in certain regions, and increases in drilling activity in others. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices. Commodity prices have been lower compared to historical periods and experienced significant volatility during recent years, as illustrated in Item 1A. Risk Factors - “Our cash flow is affected by natural gas, NGL and condensate prices.” Despite recent short-term weakness, our long-term view is that commodity prices will be at levels that we believe will support continued growth in natural gas, condensate and NGL production.

Gathering and Processing Margins - Except for our fee-based contracts, which may be impacted by throughput volumes, our natural gas gathering and processing profitability is dependent upon commodity prices, natural gas supply, and demand for natural gas, NGLs and condensate. Commodity prices, which are impacted by the balance between supply and demand, have historically been volatile. Throughput volumes could further decline should commodity prices and drilling levels continue to experience weakness. Our long-term view is that as industry conditions improve, commodity prices should support continued natural gas production in the United States. During 2016, petrochemical demand remained stable for NGLs as NGLs were a competitive feedstock when compared to crude oil derived feedstocks. We anticipate demand for NGLs by the petrochemical industry will continue in 2017 as chemical plants convert facilities from an oil-based feedstock to a NGL-based feedstock and as export facilities are brought into service. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to balance supply.

Logistics and Marketing - The volumes of NGLs transported on our pipelines, fractionated in our fractionation facilities and stored in our storage facility are dependent on the level of production of NGLs from processing plants connected to our assets. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines, fractionation and storage facilities and, in turn, lower the NGL throughput on our assets.

Factors That May Significantly Affect Our Results

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements have been adjusted to include the historical results of The DCP Midstream Business for all periods presented, similar to the pooling method. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

Gathering and Processing Segment

Our results of operations for our Gathering and Processing segment are impacted by (1) the prices of and relationship between commodities such as NGLs, crude oil and natural gas, (2) increases and decreases in the wellhead volume and quality of natural gas that we gather, (3) the associated Btu content of our system throughput and our related processing volumes, (4) the operating efficiency and reliability of our processing facilities, (5) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints, and (6) the terms of our processing contract arrangements with producers. This is not a complete list of factors that may impact our results of operations but, rather, are those we believe are most likely to impact those results.

Volume and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Volume and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Our processing contract arrangements can have a significant impact on our profitability and cash flow. Our actual contract terms are based upon a variety of factors, including the commodity pricing environment at the time the contract is executed, natural gas quality, geographic location, customer requirements and competition from other midstream service providers. Our gathering and processing contract mix and, accordingly, our exposure to natural gas, NGL and condensate prices, may change as a result of producer preferences, impacting our expansion in regions where certain types of contracts are more common as well as other market factors.

Our Gathering and Processing segment operating results are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices. The number of active oil and gas drilling rigs in the United States has decreased, from 698 on December 31, 2015 to 563 on December 31, 2016 (Source: IHS). Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term, the growth and sustainability of our business depends on commodity prices being at levels sufficient to provide incentives and capital for producers to explore for and produce natural gas.

The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close relationship. Due to our hedging program, changes in the relationship of the price of NGLs and crude oil may cause our commodity price exposure to vary, which we have attempted to capture in our commodity price sensitivities in Item 7A in our 2016 Form 10-K, “Quantitative and Qualitative Disclosures about Market Risk.” Our results may also be impacted as a result of non-cash lower of cost or market inventory or imbalance adjustments, which occur when the market value of commodities decline below our carrying value.

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

Logistics and Marketing Segment

Our Logistics and Marketing segment operating results are impacted by, among other things, the throughput volumes of the NGLs we transport on our NGL pipelines and the volumes of NGLs we fractionate and store. We transport, fractionate and store NGLs primarily on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low ethane prices relative to natural gas prices. Factors that impact the supply and demand of NGLs, as described above in our Gathering and Processing segment, may also impact the throughput and volume for our Logistics and Marketing segment.

Our results of operations for our Logistics and Marketing segment are also impacted by increases and decreases in the volume, price and basis differentials of natural gas associated with our natural gas storage and pipeline assets, as well as our underlying derivatives associated with these assets.

Weather

The economic impact of severe weather may negatively affect the nation's short-term energy supply and demand, and may result in commodity price volatility. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which restricts our production. These impacts may linger past the time of the actual weather event. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss in some instances, and in certain circumstances we have been unable to obtain insurance on commercially reasonable terms, if at all.

Capital Markets

Volatility in the capital markets may impact our business in multiple ways, including limiting our producers' ability to finance their drilling programs and operations and limiting our ability to support or fund our operations and growth. These events may impact our counterparties' ability to perform under their credit or commercial obligations. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines to mitigate a portion of these risks.

Impact of Inflation

Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our business fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high energy commodity prices.

Other

The above factors, including sustained deterioration in commodity prices and volumes, other market declines or a decline in our unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or market inventory adjustments.

Our Operations

We manage our business and analyze and report our results of operations on a segment basis. Our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing.

Gathering and Processing Segment

Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported, stored and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Gathering and Processing segment principally from contracts that contain a combination of the following arrangements:

- *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. 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.

- *Percent-of-proceeds/liquids arrangements* - Under percent-of-proceeds 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 index prices from published index market 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 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-liquids arrangements, we do not keep any amounts related to 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 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.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from production areas located in Alabama, Colorado, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas, Wyoming and the Gulf of Mexico. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. We had no supplier of natural gas representing 10% or more of our total natural gas supply during the year ended December 31, 2016. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been directly received or released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, integrated oil companies, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to third parties.

We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index.

Logistics and Marketing Segment

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

Our NGL services include plant tailgate purchases, transportation, fractionation, flexible pricing options, price risk management and product-in-kind agreements. Our primary NGL operations are generally connected to and supplied in part by our Gathering and Processing operations in each of the operating regions.

Our pipelines, fractionation facilities and storage facility provide transportation, fractionation and storage services for customers, primarily on a fee basis. We have entered into contractual arrangements that generally require customers to pay us to transport or store NGLs pursuant to a fee-based rate that is applied to volumes. These contractual arrangements may require our customers to commit a minimum level of volumes to our pipelines and facilities, thereby mitigating our exposure to volume risk. However, the results of operations for this business segment are generally dependent upon the volume of product transported, fractionated or stored and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines, fractionated in our fractionation facilities or stored in our storage facility; rather, the customer retains title and the associated commodity price risk. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. Our storage facility in Marysville, Michigan provides storage and related services primarily to regional refining and petrochemical companies and NGL marketers operating in the liquid hydrocarbons industry.

We manage our wholesale propane margins by selling propane to propane distributors under annual sales agreements negotiated each spring which specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. In addition, we may use financial derivatives to manage the value of our propane inventories.

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.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin and segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) adjusted EBITDA; (5) adjusted segment EBITDA; and (6) Distributable Cash Flow. Gross margin, segment gross margin, adjusted EBITDA, adjusted segment EBITDA, and Distributable Cash Flow are not measures under accounting principles generally accepted in the United States of America, or GAAP. To the extent permitted, we present certain non-GAAP measures and reconciliations of those measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes - We view wellhead, throughput and storage volumes for our Gathering and Processing segment and our Logistics and Marketing segment as important factors affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs and gas on our pipelines are substantially dependent upon the quantities of NGLs and gas produced at our processing plants, as well as NGLs and gas produced at other processing plants that have pipeline connections with our NGL and gas pipelines. We regularly monitor producer activity in the areas we serve and in which our pipelines are located, and pursue opportunities to connect new supply to these pipelines. We also monitor our inventory in our NGL and gas storage facilities, as well as overall demand for storage based on seasonal patterns and other market factors such as weather and overall demand.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2016, 2015 and 2014. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31,			Variance 2016 vs. 2015		Variance 2015 vs. 2014	
	2016	2015	2014	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data and percentages)						
Operating revenues (a):							
Gathering and Processing	$ 4,490	$ 4,910	$ 9,873	$ (420)	(9)%	$ (4,963)	(50)%
Logistics and Marketing	6,186	6,487	12,649	(301)	(5)%	(6,162)	(49)%
Intra-segment eliminations	(3,783)	(3,967)	(8,497)	184	5 %	4,530	53 %
Total operating revenues	6,893	7,430	14,025	(537)	(7)%	(6,595)	(47)%
Purchases:							
Gathering and Processing	(3,263)	(3,697)	(7,902)	(434)	(12)%	(4,205)	(53)%
Logistics and Marketing	(5,981)	(6,251)	(12,423)	(270)	(4)%	(6,172)	(50)%
Intra-segment eliminations	3,783	3,967	8,497	184	5 %	4,530	53 %
Total purchases	(5,461)	(5,981)	(11,828)	(520)	(9)%	(5,847)	(49)%
Operating and maintenance expense	(670)	(732)	(773)	(62)	(8)%	(41)	(5)%
Depreciation and amortization expense	(378)	(377)	(348)	1	— %	29	8 %
General and administrative expense	(292)	(281)	(277)	11	4 %	4	1 %
Asset impairments	—	(912)	(18)	(912)	(100)%	894	*
Other income (expense), net	65	(10)	(7)	75	*	(3)	(43)%
Earnings from unconsolidated affiliates (b)	282	184	82	98	53 %	102	*
Interest expense	(321)	(320)	(287)	1	— %	33	11 %
Income tax (expense) benefit	(46)	102	(11)	(148)	*	113	*
Gain (loss) on sale of assets, net	35	42	(7)	(7)	(17)%	49	*
Restructuring costs	(13)	(11)	—	2	18 %	11	*
Net income attributable to non-controlling interests	(6)	(5)	(4)	1	20 %	1	25 %
Net income (loss) attributable to partners	$ 88	$ (871)	$ 547	$ 959	*	$ (1,418)	*
Other data:							
Gross margin (c):							
Gathering and Processing	$ 1,227	$ 1,213	$ 1,971	$ 14	1 %	$ (758)	(38)%
Logistics and Marketing	205	236	226	(31)	(13)%	10	4 %
Total gross margin	$ 1,432	$ 1,449	$ 2,197	$ (17)	(1)%	$ (748)	(34)%
Non-cash commodity derivative mark-to-market	$ (139)	$ 46	$ 43	$ (185)	*	$ 3	7 %
Natural gas wellhead (MMcf/d) (d)	5,124	5,604	5,896	(480)	(9)%	(292)	(5)%
NGL gross production (MBbls/d) (d)	393	408	454	(15)	(4)%	(46)	(10)%
NGL pipelines throughput (MBbls/d) (d)	420	298	224	122	41 %	74	33 %

* Percentage change is not meaningful.

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

(b) Earnings for Discovery, Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

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

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

Year ended December 31, 2016 vs. Year ended December 31, 2015

Total Operating Revenues — Total operating revenues decreased $537 million in 2016 compared to 2015 primarily as a result of the following:

- $420 million decrease for our Gathering and Processing segment primarily due to lower commodity prices, lower gas and NGL volumes in the South, Midcontinent and Permian regions which impacted both sales and purchases, and unfavorable commodity derivative activity, which was partially offset by higher gas and NGL volumes in our North region and fee based contract realignment efforts; and improved operational efficiencies in the Permian and Midcontinent regions; and

- $301 million decrease for our Logistics and Marketing segment primarily due to lower commodity prices, lower gas and NGL sales volumes, unfavorable commodity derivative activity and lower wholesale propane fees partially offset by new connections on certain of our NGL pipelines.

These decreases were partially offset by:

- $184 million decrease in inter-segment eliminations, which related to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to lower commodity prices and lower gas and NGL sales volumes.

Total Purchases — Total purchases decreased $520 million in 2016 compared to 2015 primarily as a result of the following:

- $434 million decrease for our Gathering and Processing segment for the reasons discussed above; and

- $270 million decrease for our Logistics and Marketing segment for the reasons discussed above.

These decreases were partially offset by:

- $184 million decrease in inter-segment eliminations, which related to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to lower commodity prices and lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2016 compared to 2015 primarily as a result of our headcount reduction in April 2016, plant consolidations and other cost savings initiatives, the disposition of our Northern Louisiana system in July 2016, the sale of certain gas processing plants and gathering systems in the Permian region in 2015, partially offset by the completion of our Lucerne 2 plant in the DJ Basin system in July 2015 and the completion of our Zia II plant in the Southeast New Mexico system in August 2015.

General and Administrative Expense — General and administrative expense increased in 2016, compared to 2015, primarily due to nonrecurring costs driven by the closing of the Transaction as described in the recent events section, partially offset by our headcount reduction in April 2016 and other cost savings initiatives.

Asset Impairments - Asset impairments in 2015 represented impairments of goodwill, property, plant and equipment and intangible assets.

Other Income (Expense), net — Other income, net in 2016 represented a producer settlement net of legal fees, partially offset by charges for discontinued construction projects. Other expense, net in 2015 primarily represented charges for discontinued construction projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2016 compared to 2015, primarily as a result of Enbridge's contribution of its interests in Sand Hills and Southern Hills in November 2015, higher pipeline throughput volumes on Southern Hills, Sand Hills and Front Range due to growth in NGL production from new plants placed into service in 2015 and as a result of the ramp-up of the Keathley Canyon volumes at Discovery.

Income Tax (Expense) Benefit — Income tax benefit decreased in 2016 compared to 2015 primarily due to impairments of property, plant and equipment and intangible assets recorded in the fourth quarter of 2015.

Gain (loss) on Sale of Assets, Net — Gain on sale of assets during 2016 primarily related to the sale of our Northern Louisiana system. During 2015, we recognized gains related to the sale of certain gas processing plants and gathering systems.

Net Income Attributable to Partners — Net income attributable to partners increased in 2016 compared to 2015 for the reasons discussed above.

Gross Margin — Gross margin decreased $17 million in 2016 compared to 2015 primarily as a result of the following:

- $31 million decrease for our Logistics and Marketing segment primarily related to unfavorable commodity derivative activity, the sale of our Northern Louisiana system in July 2016 and lower wholesale propane fees, partially offset by new connections on certain of our NGL pipelines.

  These decreases were partially offset by:

- $14 million increase for our Gathering and Processing segment primarily due to the ramp-up of the Lucerne 2 plant in June 2015, completion of the Grand Parkway gathering system in January 2016, higher margins on a specific producer arrangement, higher NGL recoveries in our North region, completion of the Zia II plant in August 2015 in our Permian region, ramp-up of the National Helium plant in September 2015 in our Midcontinent region, fee based contract realignment efforts and improved operational efficiencies in our Permian and Midcontinent regions, partially offset by lower commodity prices, lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods, unfavorable derivative activity and the sale of our Northern Louisiana system.

Year Ended December 31, 2015 vs. Year Ended December 31, 2014

Total Operating Revenues — Total operating revenues decreased $6,595 million in 2015 compared to 2014 primarily as a result of the following:

- $4,963 million decrease for our Gathering and Processing segment primarily due to lower commodity prices and lower gas and NGL volumes in the South, Midcontinent and Permian regions which impacted both sales and purchases, partially offset by higher gas and NGL volumes in our North region, favorable commodity derivative activity and fee based contract realignment efforts and the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions, partially offset by the completion and ramp-up of the Lucerne 2 plant in June 2015, completion and ramp-up of the Zia II plant in August 2015 and ramp-up of the National Helium plant in September 2015; and

- $6,162 million decrease for our Logistics and Marketing segment primarily due to lower commodity prices, lower gas and NGL sales volumes and unfavorable commodity derivative activity, partially offset by the conversion of one of our assets to a butane export facility and higher NGL storage margins.

  These decreases were partially offset by:

- $4,530 million increase in inter-segment eliminations, which relate to sales of NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to lower commodity prices and lower gas and NGL sales volumes.

Total Purchases — Total purchases decreased $5,847 million in 2015 compared to 2014 primarily as a result of the following:

- $4,205 million decrease for our Gathering and Processing segment for the reasons discussed above; and

- $6,172 million decrease for our Logistics and Marketing segment for the reasons discussed above.

  These decreases were partially offset by:

- $4,530 million decrease in inter-segment eliminations, which relate to sales of NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to lower commodity prices and lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2015 compared 2014 primarily as a result of the sale of certain gas processing plants and gathering systems in the Permian region in 2015 and other cost savings initiatives. In addition, 2014 results included higher spending on reliability programs.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2015 compared to 2014 primarily as a result the completion of expansion projects including the Lucerne 2 plant in our DJ Basin system in our North Region and the completion of the Zia II plant in our Southeast New Mexico system in our Permian region, partially offset by the sale of certain gas processing plants and gathering systems in our Permian region.

Asset Impairments — Asset impairments in 2015 represented impairments of goodwill, property, plant and equipment and intangible assets. During the same period in 2014, asset impairments represented the impairment of goodwill.

Other Income (Expense), net — Other expense, net in 2015 and 2014 primarily represented discontinued construction projects.

Gain (loss) on Sale of Assets, net — Gain on sale of assets for the year ended December 31, 2015 primarily related to the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions. During the same period in 2014, we recognized a loss related to the sale of an investment in an unconsolidated affiliate.

Earnings from Unconsolidated Affiliates — Equity in earnings of unconsolidated affiliates increased in 2015 compared to 2014, primarily attributable to the ramp-up of Sand Hills and Front Range, the completion of the Keathley Canyon project at Discovery in February 2015 and Enbridge's contribution of its interests in Sand Hills and Southern Hills in the fourth quarter of 2015.

Interest Expense, net — Interest expense increased in 2015 compared to 2014 as a result of higher average outstanding debt balances associated with the growth of our operations and lower capitalized interest.

Income Tax (Expense) Benefit — Income tax benefit (expense) increased in 2015 compared to 2014 primarily attributable to impairments of property, plant and equipment and intangible assets recorded in the fourth quarter of 2015.

Restructuring Costs — As part of our initial phase in our restructuring plan to reduce general and administrative and non-core operational costs, we recorded approximately $11 million in employee termination costs during 2015.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

Earnings from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2016	2015	2014
	(Millions)		
DCP Sand Hills Pipeline, LLC	$ 110	$ 63	$ 26
Discovery Producer Services LLC	73	54	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 1 Fractionator	9	9	12
Texas Express Pipeline LLC	9	8	3
Other	2	—	—
Total earnings from unconsolidated affiliates	$ 282	$ 184	$ 82

Distributions received from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2016	2015	2014
	(Millions)		
DCP Sand Hills Pipeline, LLC	$ 139	$ 71	$ 43
Discovery Producer Services LLC	94	69	15
DCP Southern Hills Pipeline, LLC	56	24	23
Front Range Pipeline LLC	24	17	15
Mont Belvieu Enterprise Fractionator	18	13	19
Mont Belvieu 1 Fractionator	11	12	14
Texas Express Pipeline LLC	11	11	8
Other	3	—	4
Total distributions from unconsolidated affiliates	$ 356	$ 217	$ 141

Results of Operations — Gathering and Processing Segment

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

	Year Ended December 31,			Variance 2016 vs. 2015		Variance 2015 vs. 2014	
	2016	2015	2014	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 3,955	$ 4,377	$ 9,375	$ (422)	(10)%	$ (4,998)	(53)%
Transportation, processing and other	580	465	463	115	25 %	2	— %
Trading and marketing (losses) gains, net	(45)	68	35	(113)	*	33	94 %
Total operating revenues	4,490	4,910	9,873	(420)	(9)%	(4,963)	(50)%
Purchases of natural gas and NGLs	(3,263)	(3,697)	(7,902)	(434)	(12)%	(4,205)	(53)%
Operating and maintenance expense	(611)	(668)	(725)	(57)	(9)%	(57)	(8)%
Depreciation and amortization expense	(344)	(343)	(315)	1	— %	28	9 %
General and administrative expense	(14)	(22)	(27)	(8)	(36)%	(5)	(19)%
Asset impairments	—	(876)	(18)	(876)	(100)%	858	*
Other income (expense), net	73	(1)	(5)	74	*	4	*
Earnings from unconsolidated affiliates (a)	73	54	5	19	35 %	49	*
Gain (loss) on sale of assets, net	19	42	(7)	(23)	(55)%	49	*
Segment net income (loss)	423	(601)	879	1,024	*	(1,480)	*
Segment net income attributable to non-controlling interests	(6)	(5)	(4)	1	20 %	1	25 %
Segment net income (loss) attributable to partners	$ 417	$ (606)	$ 875	$ 1,023	*	$ (1,481)	*
Other data:							
Segment gross margin (b)	$ 1,227	$ 1,213	$ 1,971	$ 14	1 %	$ (758)	(38)%
Non-cash commodity derivative mark-to-market	$ (119)	$ 47	$ 39	$ (166)	*	$ 8	21 %
Natural gas throughput wellhead (MMcf/d) (c)	5,124	5,604	5,896	(480)	(9)%	(292)	(5)%
NGL gross production (MBbls/d) (c)	393	408	454	(15)	(4)%	(46)	(10)%

* Percentage change is not meaningful.

(a) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery. Earnings for Discovery include the amortization of the net difference between the carrying amount of our investment and the underlying equity of the entity.

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

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

Year Ended December 31, 2016 vs. Year Ended December 31, 2015

Total Operating Revenues — Total operating revenues decreased $420 million in 2016 compared to 2015, primarily as a result of the following:

- $163 million decrease attributable to lower commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $444 million decrease attributable to lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods, partially offset by improved operational efficiencies in the Permian and Midcontinent regions; and
- $113 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $166 million in 2016 which were partially offset by a $53 million increase in realized cash settlement gains due to movements in forward prices of commodities.

These decreases were partially offset by:

- $185 million increase attributable to higher gas and NGL sales volumes and the impact of a specific producer arrangement primarily related to our DJ Basin system in our North region;
- $115 million increase in transportation, processing and other primarily related to fee based contract realignment efforts, partially offset by lower volumes in the South region and the sale of our Northern Louisiana System.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $434 million in 2016 compared to 2015 as a result of decreased commodity prices and lower gas and NGL sales volumes in our South, Midcontinent and Permian regions, partially offset by increased volumes in our North region.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2016 compared to 2015 primarily as a result of our headcount reduction in April 2016, plant consolidations and other cost savings initiatives, the disposition of our Northern Louisiana system in July 2016 and the sale of certain gas processing plants and gathering systems in the Permian region in 2015, partially offset by the completion of our Lucerne 2 plant in the DJ Basin system in July 2015 and the completion of our Zia II plant in the Southeast New Mexico system in August 2015.

General and Administrative Expense — General and administrative expense decreased in 2016 compared to 2015 primarily as a result of our headcount reduction in April 2016 and other cost savings initiatives.

Asset Impairments — Asset impairments in 2015 represented impairments of goodwill, property, plant and equipment and intangible assets.

Other Income (Expense), net — Other income, net in 2016 represented a producer settlement net of legal fees, partially offset by charges from discontinued construction projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2016 compared to 2015 primarily as a result of the ramp-up of the Keathley Canyon volumes at Discovery.

Gain on Sale of Assets, net — Gain on sale of assets during 2016 primarily related to the sale of our Northern Louisiana system in our South region. During 2015, we recognized gains related to the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions.

Segment Gross Margin — Segment gross margin increased $14 million in 2016 compared to 2015, primarily as a result of the following:

- $76 million increase primarily as a result of higher volumes following the ramp-up of the Lucerne 2 plant, completion of the Grand Parkway gathering system in January 2016, higher margins on specific producer arrangements and higher NGL recoveries primarily related to our DJ Basin system in our North region;
- $77 million increase primarily as a result of the completion of the Zia II plant in the Southeast New Mexico system in our Permian region in August 2015, ramp-up of the National Helium plant in the Liberal system in our Midcontinent region in September 2015 and improved operational efficiencies in the Permian and Midcontinent regions; and

- $12 million increase primarily as a result of fee based contract realignment efforts in the Permian and Midcontinent regions, partially offset by lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods.

  These increases were partially offset by:

- $113 million decrease as a result of commodity derivative activity as discussed above;

- $30 million decrease as a result of lower commodity prices; and

- $8 million decrease as a result of the sale of our Northern Louisiana system in our South Region.

Total Wellhead Volumes - Natural gas wellhead throughput decreased in 2016 compared to 2015 reflecting lower volumes primarily from (i) our Eagle Ford and East Texas systems within our South region (ii) lower volumes associated with the general declines within the Permian and Midcontinent regions (iii) the disposition of our Northern Louisiana system within our South region and (iv) disposition of certain gas processing plants and gathering systems in the Midcontinent and Permian regions, which were partially offset by (i) the ramp-up of the Lucerne 2 plant in our North region which commenced operations in June 2015 (ii) completion of the Zia II plant in August 2015 and (iii) ramp-up of the National Helium plant in September 2015.

NGL Gross Production - NGL production decreased in 2016 compared to 2015 reflecting lower volumes primarily from (i) our Eagle Ford and East Texas systems within our South region (ii) lower volumes associated with the general declines within the Permian and Midcontinent regions (iii) the disposition of our Northern Louisiana system within our South region (iv) disposition of certain gas processing plants in the Midcontinent and Permian regions and (v) higher ethane rejection, which were partially offset by (i) the ramp-up of the Lucerne 2 plant in our North region which commenced operations in June 2015 (ii) completion of the Zia II plant in August 2015 and (iii) ramp-up of the National Helium plant in September 2015.

Year Ended December 31, 2015 vs. Year Ended December 31, 2014

Total Operating Revenues — Total operating revenues decreased $4,963 million in 2015 compared to 2014, primarily as a result of the following:

- $4,284 million decrease attributable to lower commodity prices, which impacted both sales and purchases, before the impact of derivative activity; and
- $915 million decrease attributable to lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in the current period and the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions, partially offset by the completion and ramp-up of the Lucerne 2 plant in June 2015, completion and ramp-up of the Zia II plant in August 2015 and ramp-up of the National Helium plant in September 2015.

  These decreases were partially offset by:

- $201 million increase attributable to higher gas and NGL sales volumes primarily related to our DJ Basin system in our North region;

- $2 million increase in transportation, processing and other primarily related to fee based contract realignment efforts; and

- $33 million increase as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative gains of $8 million in 2015 and $25 million increase in realized cash settlement gains due to movements in forward prices of commodities.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $4,205 million in 2015 compared to 2014 primarily as a result of decreased commodity prices and lower gas and NGL sales volumes in our South, Midcontinent and Permian regions and the sale of certain gas processing plants in our Midcontinent and Permian regions, partially offset by the completion and ramp-up of the Lucerne 2 plant in June 2015, completion and ramp-up of the Zia II plant in August 2015 and ramp-up of the National Helium plant in September 2015.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2015 compared to 2014 primarily as a result of the sales of certain gas processing plants and gathering systems in the Permian region in 2015 and other cost savings initiatives. In addition, 2014 results included higher spending on reliability programs.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2015 compared to 2014 primarily as a result of the completion of expansion projects including the Lucerne 2 plant in our DJ Basin system in our North Region and the Zia II plant in our Southeast New Mexico system in our Permian region, partially offset by the sale of certain gas processing plants and gathering systems in our Permian region.

General and Administrative Expense — General and administrative expense decreased in 2015 compared to 2014 primarily as a result of our headcount reduction in January 2015.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2015 compared to 2014 primarily as a result of the completion and ramp-up of the Keathley Canyon project at Discovery in February 2015.

Asset Impairments — Asset impairments in 2015 represented impairments of goodwill, property, plant and equipment and intangible assets. During the same period in 2014, asset impairments represent the impairment of goodwill.

Other (Income) Expense, net — Other expense, net in 2015 and 2014 primarily represented charges for discontinued construction projects.

Gain on Sale of Assets, net — Gain on sale of assets for the year ended December 31, 2015 primarily related to the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions. During the same period in 2014, we recognized a loss related to the sale of an investment in an unconsolidated affiliate.

Segment Gross Margin — Segment gross margin decreased $758 million in 2015 compared to 2014, primarily as a result of the following:

- $897 million decrease as a result of lower commodity prices; and
- $44 million decrease primarily as a result of lower volumes across our Midcontinent, South and Permian regions due to reduced drilling activity in 2015 and the sale of certain gas processing plants in our Midcontinent and Permian regions, partially offset by fee based contract realignment efforts across our Midcontinent, South and Permian regions.

These decreases were partially offset by:

- $83 million increase primarily as a result of higher volumes following the completion and ramp-up of the Lucerne 2 plant in June 2015, higher NGL recoveries primarily related to our DJ Basin system in our North region and higher margins on a specific producer arrangement;
- $67 million increase primarily as a result of the completion and ramp-up of the Zia II plant in the Southeast New Mexico system in our Permian region in August 2015, ramp-up of the National Helium plant in the Liberal system in our Midcontinent region in September 2015 and improved plant operational efficiencies in the Permian and Midcontinent regions; and
- $33 million increase as a result of commodity derivative activity as discussed above.

Total Wellhead Volumes — Natural gas wellhead throughput decreased in 2015 compared to 2014 reflecting lower volumes primarily from (i) our Eagle Ford and East Texas systems within our South region (ii) lower volumes associated with the general declines within the Permian and Midcontinent regions and (iii) the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions, which were partially offset by (i) the completion and ramp-up of the Keathley Canyon project at Discovery which commenced operations in February 2015 (ii) Lucerne 2 plant in our DJ Basin system in our North region which commenced operations in June 2015 (iii) completion of our Zia II plant in our Southeast New Mexico system in our Permian region in August 2015 and (iv) ramp-up of our National Helium plant in our Liberal system in our Midcontinent region in September 2015.

NGL Gross Production — NGL gross production decreased in 2015 compared to 2014 reflecting lower volumes primarily from (i) our Eagle Ford and East Texas systems within our South region (ii) lower volumes associated with the general declines within the Permian and Midcontinent regions and (iii) the sale of certain gas processing plants and gathering systems in our Midcontinent and Permian regions, which were partially offset by (i) the completion and ramp-up of the Keathley Canyon project at Discovery which commenced operations in February 2015 (ii) Lucerne 2 plant in our DJ Basin system in our North region which commenced operations in June 2015 (iii) completion of our Zia II plant in our Southeast New Mexico system in our Permian region in August 2015 and (iv) ramp-up of our National Helium plant in our Liberal system in our Midcontinent region in September 2015.

Results of Operations — Logistics and Marketing Segment

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

	Year Ended December 31,			Variance 2016 vs. 2015		Variance 2015 vs. 2014	
	2016	2015	2014	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 6,094	$ 6,364	$ 12,540	$ (270)	(4)%	$ (6,176)	(49)%
Transportation, processing and other	70	72	56	(2)	(3)%	16	29 %
Trading and marketing gains, net	22	51	53	(29)	(57)%	(2)	(4)%
Total operating revenues	6,186	6,487	12,649	(301)	(5)%	(6,162)	(49)%
Purchases of natural gas and NGLs	(5,981)	(6,251)	(12,423)	(270)	(4)%	(6,172)	(50)%
Operating and maintenance expense	(43)	(49)	(44)	(6)	(12)%	5	11 %
Depreciation and amortization expense	(15)	(16)	(17)	(1)	(6)%	(1)	(6)%
General and administrative expense	(9)	(11)	(14)	(2)	(18)%	(3)	(21)%
Asset impairments	—	(9)	—	(9)	(100)%	9	*
Other expense, net	(5)	(8)	—	(3)	(38)%	8	*
Gain on sale of assets, net	16	—	—	16	*	—	*
Earnings from unconsolidated affiliates (a)	209	130	77	79	61 %	53	69 %
Segment net income	358	273	228	85	31 %	45	20 %
Segment net income attributable to non-controlling interests	—	—	—	—	*	—	*
Segment net income attributable to partners	$ 358	$ 273	$ 228	$ 85	31 %	$ 45	20 %
Other data:							
Segment gross margin (b)	$ 205	$ 236	$ 226	$ (31)	(13)%	$ 10	4 %
Non-cash commodity derivative mark-to-market	$ (20)	$ (1)	$ 4	$ (19)	*	$ (5)	*
NGL pipelines throughput (MBbls/d)	420	298	224	122	41 %	74	33 %

(a) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the throughput volumes of unconsolidated affiliates. Earnings for Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of our investments and the underlying equity of the entities.

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

Year Ended December 31, 2016 vs. Year Ended December 31, 2015

Total Operating Revenues — Total operating revenues decreased $301 million in 2016 compared to 2015, primarily as a result of the following:

- $250 million decrease attributable to lower commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $20 million decrease attributable to lower gas and NGL sales volumes, which impacted both sales and purchases
- $29 million decrease as a result of commodity derivative activity attributable to a $10 million decrease in realized cash settlement gains in 2016 and an increase in unrealized commodity derivative losses of $19 million due to movements in forward prices of commodities; and
- $2 million decrease primarily due to the sale of our Northern Louisiana system in July 2016 and lower wholesale propane fees partially offset by new connections on certain of our NGL pipelines.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $270 million in 2016 compared to 2015 as a result of lower commodity prices and lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2016 compared to 2015 primarily as a result of our headcount reduction in April 2016, other cost savings initiatives and the sale of our Northern Louisiana system in July 2016.

General and Administrative Expense — General and administrative expense decreased in 2016 compared to 2015 primarily as a result of our headcount reduction in April 2016 and other cost savings initiatives.

Asset Impairments — Asset impairments for the year ended December 31, 2015 primarily related to impairments of property, plant and equipment and intangible assets.

Other Expense, net — Other expense, net in 2016 and 2015 primarily represents charges for discontinued construction projects.

Gain on Sale of Assets, net — Gain on sale of assets for the year ended December 31, 2016 primarily related to the sale of our Northern Louisiana system.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2016 compared to 2015 primarily as a result of Enbridge's contribution of its interests in Sand Hills and Southern Hills in November 2015, higher pipeline throughput volumes on Southern Hills, Sand Hills and Front Range due to growth in NGL production from new plants placed into service in 2015 and earnings on the Panola pipeline beginning in February 2016.

Segment Gross Margin — Segment gross margin decreased $31 million in 2016 compared to 2015, primarily as a result of the following:

- $29 million decrease as a result of commodity derivative activity attributable to a $10 million decrease in realized cash settlement gains in 2016 and an increase in unrealized commodity derivative losses of $19 million due to movements in forward prices of commodities;
- $2 million decrease primarily due to the sale of our Northern Louisiana system in July 2016 and lower wholesale propane fees, partially offset by new connections on certain of our NGL pipeline.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2016 compared to 2015 primarily as a result of Enbridge's contribution of its interests in Sand Hills and Southern Hills in November 2015, higher throughput volumes on Sand Hills, Southern Hills and Front Range due to growth in NGL production from new plants placed into service in 2015 and the throughput volumes on Panola commencing February 2016.

Year Ended December 31, 2015 vs. Year Ended December 31, 2014

Total Operating Revenues — Total operating revenues decreased $6,162 million in 2015 compared to 2014, primarily as a result of the following:

- $5,682 million decrease attributable to lower commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $494 million decrease attributable to lower gas and NGL sales volumes, which impacted both sales and purchases; and
- $2 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $5 million in 2015 partially offset by a $3 million increase in realized cash settlement gains due to movements in forward prices of commodities.

  These decreases were partially offset by:

- $16 million increase primarily attributable to the conversion of one of our assets to a butane export facility and higher NGL storage margins.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $6,172 million in 2015 compared to 2014 as a result of decreased commodity prices and lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2015 compared to 2014 primarily as a result of increased asset reliability spending, partially offset by our headcount reduction in January 2015 and other cost savings initiatives.

Asset Impairments — Asset impairments for the year ended December 31, 2015 primarily related to impairments of property, plant and equipment and intangible assets.

Other Expense — Other expense, net in 2015 primarily represents charges for discontinued construction projects.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2015 compared to 2014 primarily as a result of the Enbridge's contribution of its interests in Sand Hills and Southern Hills in November 2015 and the ramp-up of Sand Hills and Texas Express and Front Range which commenced operations in February 2014, partially offset by reduced fractionated volumes at both of our Mont Belvieu fractionators and unfavorable location pricing at one of our Mont Belvieu fractionators.

Segment Gross Margin — Segment gross margin increased $10 million in 2015 compared to 2014, primarily as a result of the following:

- $16 million increase primarily attributable to the conversion of one of our assets to a butane export facility and higher NGL storage margins; and
- $27 million increase from wholesale propane primarily due to a partial recovery of lower of cost or market inventory adjustments recognized in the fourth quarter of 2014 and higher unit margins, partially offset by a decrease in volumes.

These increases were partially offset by:

- $31 million decrease primarily attributable lower volumes and unit margins on our natural gas storage assets and decreased gains from NGL marketing; and
- $2 million decrease as a result of commodity derivative activity attributable to a an increase in unrealized commodity derivative losses of $5 million in 2015 partially offset by a $3 million increase in realized cash settlement gains due to movements in forward prices of commodities.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2015 compared to 2014 as a result of Enbridge's contribution of its interests in Sand Hills and Southern Hills in November 2015, volume growth on certain of our pipelines including Sand Hills and Southern Hills, Front Range which commenced operations in February 2014 and the ramp-up of Texas Express.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our Amended and Restated Credit Agreement;
- debt offerings;
- issuances of additional common units;
- borrowings under term loans; and
- letters of credit.

We anticipate our more significant uses of resources to include:

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

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure, debt service obligations, and acquisition requirements, and quarterly cash distributions for the next twelve months.

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

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

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

As of December 31, 2016, there was $195 million of outstanding borrowings on the revolving credit facility under the Amended and Restated Credit Agreement. We had unused borrowing capacity of $1,031 million, net of $24 million of letters of credit, under the Amended and Restated Credit Agreement. The financial covenants set forth in the Amended and Restated Credit Agreement limit the Partnership's ability to incur incremental debt by $970 million as of December 31, 2016. We used a portion of the cash received from the Transaction to repay outstanding debt on our revolving credit facility. Our cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings-based pricing grid. In the first quarter of 2017, our credit rating was lowered. As a result of this action, interest rates on outstanding borrowings under the Amended and Restated Credit Agreement increased. As of May 19, 2017, we had no outstanding borrowings on the revolving credit facility and had approximately $1,374 million, net of $24 million of letters of credit, of unused borrowing capacity under the Amended and Restated Credit Agreement.

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

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

We also have a shelf registration statement that was declared effective in July 2014 allowing us to issue up to $500 million in common units pursuant to our 2014 equity distribution agreement. During the year ended December 31, 2016, we issued no common units and approximately $349 million of common units remained available for sale pursuant to our 2014 equity distribution agreement.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through the first quarter of 2018 with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" in our Annual Report on Form 10-K.

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

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

We had working capital deficits of $629 million and $95 million as of December 31, 2016 and 2015, respectively. The change in working capital is primarily attributable to current maturities of our long-term debt of $500 million as of December 31, 2016. We had a net derivative working capital deficit of $49 million as of December 31, 2016 as compared to net derivative working capital excess of $87 million as of December 31, 2015.

As of December 31, 2016, we had $1 million in cash and cash equivalents, all of which was held by consolidated subsidiaries we did not wholly own.

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

	Year Ended December 31,		
	2016	2015	2014
	(Millions)		
Net cash provided by operating activities	$ 645	$ 442	$ 817
Net cash used in investing activities	$ (34)	$ (711)	$ (1,515)
Net cash (used in) provided by financing activities	$ (613)	$ 245	$ 694

Year Ended December 31, 2016 vs. Year Ended December 31, 2015

Operating Activities — Net cash provided by operating activities increased $203 million in 2016 compared to 2015 primarily as a result of the following:

- $279 million increase in cash attributable to higher net income in 2016, after adjusting our net income for asset impairments in 2015 and other non-cash items;
- $139 million increase in cash distributions from unconsolidated affiliates due to increased earnings. For additional information regarding fluctuations in our earnings from unconsolidated affiliates, please read "Results of Operations"; and
- $215 million decrease in cash attributable to the timing of cash receipts and disbursements related to operations.

Investing Activities — Net cash used in investing activities decreased $677 million in 2016 compared to 2015 primarily as a result of the following:

- $667 million decrease in capital expenditures attributable to the Lucerne 2 plant which started construction in April 2014 and was placed into service at the end of the second quarter of 2015, the Zia II plant which was placed into service in August 2015, the National Helium plant which was expanded and was placed into service in September 2015 and the Grand Parkway gathering project which began construction in the first quarter of 2015 and was completed in the first quarter of 2016; and
- $11 million decrease in cash contributions to our unconsolidated affiliates. For the year ended December 31, 2016, we primarily made contributions to the expansion projects at our Sand Hills and Southern Hills pipelines and the construction of our Panola pipeline. For the year ended December 31, 2015, we primarily made contributions to the Keathley Canyon project at Discovery, our Panola pipeline and to the expansion projects at our Sand Hills pipeline.
- $1 million of lower proceeds received from the sale of assets in 2016.

Financing Activities — Net cash used in financing activities increased $858 million in 2016 compared to 2015 primarily as a result of the following:

- $1,540 million decrease in advances from DCP Midstream, LLC primarily attributable to the $1,500 million contribution received from Phillips 66 in 2015;
- $31 million decrease in proceeds from the issuance of common units to the public. We issued no common units to the public during the year ended December 31, 2016 as compared to approximately 1 million common units that were issued during the year ended December 31, 2015;
- $2 million increase in distributions to non-controlling interests primarily due to Collbran; and
- $1 million increase in distributions to limited and general partners.

These events were partially offset by:

- $716 million decrease in net debt payments primarily attributable to the repayment of outstanding commercial paper in 2015.

Year Ended December 31, 2015 vs. Year Ended December 31, 2014

Operating Activities — Net cash provided by operating activities decreased $375 million in 2015 compared to 2014 primarily as a result of the following:

- $76 million increase in cash distributions from unconsolidated affiliates primarily due to increased earnings. For additional information regarding fluctuations in our earnings from unconsolidated affiliates, please read "Results of Operations";
- $301 million increase in cash attributable to the timing of cash receipts and disbursements related to operations; and
- $752 million decrease in cash attributable to higher net income in 2014, after adjusting our net income for asset impairments and other non-cash items.

Investing Activities — Net cash used in investing activities decreased $804 million in 2015 compared to 2014 primarily as a result of the following:

- $573 million decrease in capital expenditures attributable to the completion of the Goliad plant and the O'Connor plant expansion, both of which were completed in the first quarter of 2014, the Lucerne 2 plant which started construction in April 2014 and was placed into service at the end of the second quarter of 2015, the Zia II plant which was placed into service in the August 2015, the National Helium plant which was expanded and placed into service in the September 2015, partially offset by the Grand Parkway gathering project which began construction in the first quarter of 2015;
- $97 million decrease in cash contributions to our unconsolidated affiliates. In 2014, we primarily made contributions to the Keathley Canyon project at Discovery, which was placed into service in the first quarter of 2015, and Front Range, which was placed into service in February 2014. In 2015, we primarily made contributions to the Keathley Canyon project at Discovery, our Panola pipeline and to the expansion projects at our Sand Hills pipeline; and
- $134 million of higher proceeds received from the sale of certain gas processing plants and gathering systems assets in 2015.

Financing Activities — Net cash provided by financing activities decreased $449 million in 2015 compared to 2014 primarily as a result of the following:

- $970 million decrease in proceeds from the issuance of common units to the public. We issued approximately 1 million common units to the public during the year ended December 31, 2015 as compared to approximately 20 million units during the year ended December 31, 2014;
- $1,415 million decrease in net debt borrowings primarily attributable to the higher repayments of outstanding commercial paper in 2015. In 2014, we received $719 million of proceeds from senior notes associated with the March 2014 Transactions; and
- $62 million increase in cash distributions to our limited and general partners primarily attributable to units issued during 2014 and an increase in our quarterly distribution rate over the rate paid for the year ended December 31, 2014.

These events were partially offset by:

- $1,998 million increase in advances from DCP Midstream, LLC primarily attributable to the $1,500 million contribution received from Phillips 66 in 2015 and $222 million paid related to our March 2014 Transactions.

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

- maintenance capital expenditures, which are cash expenditures to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets; and
- expansion capital expenditures, which are cash expenditures to increase our cash flows, operating or earnings capacity. Expansion capital expenditures include acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines and well connects, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets).

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

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

	Year Ended December 31, 2016			Year Ended December 31, 2015		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 86	$ 57	$ 143	$ 181	$ 633	$ 814
Non-controlling interest portion and reimbursable projects (a)	3	(2)	1	(3)	—	(3)
Total	$ 89	$ 55	$ 144	$ 178	$ 633	$ 811

	Year Ended December 31, 2014		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)		
Our portion	$ 344	$ 1,039	$ 1,383
Non-controlling interest portion and reimbursable projects (a)	2	(1)	1
Total	$ 346	$ 1,038	$ 1,384

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

In addition, we invested cash in unconsolidated affiliates of $53 million and $64 million during the years ended December 31, 2016 and 2015, respectively, to fund our share of capital expansion projects.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon internal and external financing sources, to fund future acquisitions and capital expenditures.

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

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $483 million and $482 million during the years ended December 31, 2016 and 2015, respectively. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 14. "Partnership Equity and Distributions" in the Notes to Consolidated Financial Statements in Exhibit 99.4 “Financial Statements.” in this Form 8-K.

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of December 31, 2016, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(Millions)				
Debt (a)	$ 8,740	$ 786	$ 1,491	$ 1,494	$ 4,969
Operating lease obligations	225	61	72	50	42
Purchase obligations (b)	2,911	619	768	674	850
Other long-term liabilities (c)	145	—	11	8	126
Total	$ 12,021	$ 1,466	$ 2,342	$ 2,226	$ 5,987

(a) Includes interest payments on debt securities that have been issued. These interest payments are $286 million, $521 million, $394 million, and $2,119 million for less than one year, one to three years, three to five years, and thereafter, respectively.

(b) Our purchase obligations are contractual obligations and include purchase orders and non-cancelable construction agreements for capital expenditures, various non-cancelable commitments to purchase physical quantities of commodities in future periods and other items, including long-term fractionation agreements. For contracts where the price paid is based on an index or other market-based rates, the amount is based on the forward market prices or current market rates as of December 31, 2016. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include asset retirement obligations, long-term environmental remediation liabilities, gas purchase liabilities, right of way liabilities and other miscellaneous liabilities recognized in the December 31, 2016 condensed consolidated balance sheet. The table above excludes non-cash obligations as well as $28 million of deferred state income taxes, $26 million of Executive Deferred Compensation Plan contributions and $12 million of long-term incentive plans as the amount and timing of any payments are not subject to reasonable estimation.

Off-Balance Sheet Obligations

As of December 31, 2016, we had no items that were classified as off-balance sheet obligations.

Reconciliation of Non-GAAP Measures

Gross Margin and Segment Gross Margin — In addition to net income, we view our gross margin as an important performance measure of the core profitability of our operations. We review our gross margin monthly for consistency and trend analysis.

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

Adjusted EBITDA —We define adjusted EBITDA as net income or loss attributable to partners adjusted for (i) distributions from unconsolidated affiliates, net of earnings (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations.. Management believes these measures provide investors meaningful insight into results from ongoing operations.

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

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

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

Adjusted Segment EBITDA — We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners adjusted for (i) distributions from unconsolidated affiliates, net of earnings (ii) depreciation and amortization expense, (iii) net interest expense, (iv) non-controlling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted segment EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations for that segment. Our adjusted segment EBITDA may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

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

Our gross margin, segment gross margin, adjusted EBITDA and adjusted segment EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner. The accompanying schedules provide reconciliations of gross margin, segment gross margin and adjusted segment EBITDA to their most directly comparable GAAP financial measures.

Distributable Cash Flow — We define Distributable Cash Flow as adjusted EBITDA, as defined above, less maintenance capital expenditures, net of reimbursable projects, less interest expense and certain other items. Maintenance capital expenditures are cash expenditures made to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing Distributable Cash Flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices and interest rates. We compare the Distributable Cash Flow we generate to the cash distributions we expect to pay our partners. Using this metric, we compute our distribution coverage ratio. Distributable Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner.

Our Distributable Cash Flow may not be comparable to a similarly titled measure of another company because other entities may not calculate Distributable Cash Flow in the same manner.

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

	Year Ended December 31,		
	2016	2015	2014
Reconciliation of Non-GAAP Measures		(Millions)	
Reconciliation of net income attributable to partners to gross margin:			
Net income (loss) attributable to partners	$ 88	$ (871)	$ 547
Interest expense	321	320	287
Income tax expense (benefit)	46	(102)	11
Operating and maintenance expense	670	732	773
Depreciation and amortization expense	378	377	348
General and administrative expense	292	281	277
Asset impairments	—	912	18
Other (income) expense, net	(65)	10	7
Earnings from unconsolidated affiliates	(282)	(184)	(82)
(Gain) loss on sale of assets, net	(35)	(42)	7
Restructuring costs	13	11	—
Net income attributable to non-controlling interests	6	5	4
Gross margin	$ 1,432	$ 1,449	$ 2,197
Non-cash commodity derivative mark-to-market (a)	$ (139)	$ 46	$ 43
Reconciliation of segment net income attributable to partners to segment gross margin:			
Gathering and Processing Segment:			
Segment net income (loss) attributable to partners	$ 417	$ (606)	$ 875
Operating and maintenance expense	611	668	725
Depreciation and amortization expense	344	343	315
General and administrative	14	22	27
Other (income) expense, net	(73)	1	5
Earnings from unconsolidated affiliates	(73)	(54)	(5)
(Gain) loss on sale of assets, net	(19)	(42)	7
Asset impairments	—	876	18
Net income attributable to non-controlling interests	6	5	4
Segment gross margin	$ 1,227	$ 1,213	$ 1,971
Non-cash commodity derivative mark-to-market (a)	$ (119)	$ 47	$ 39
Logistics and Marketing Segment:			
Segment net income attributable to partners	$ 358	$ 273	$ 228
Operating and maintenance expense	43	49	44
Depreciation and amortization expense	15	16	17
General and administrative	9	11	14
Other expense, net	5	8	—
Earnings from unconsolidated affiliates	(209)	(130)	(77)
Gain on sale of assets, net	(16)	—	—
Asset impairments	—	9	—
Segment gross margin	$ 205	$ 236	$ 226
Non-cash commodity derivative mark-to-market (a)	$ (20)	$ (1)	$ 4

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

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Reconciliation of net income attributable to partners to adjusted segment EBITDA:			
Gathering and Processing segment:			
Segment net income (loss) attributable to partners	$ 417	$ (606)	$ 875
Non-cash commodity derivative mark-to-market	119	(47)	(39)
Depreciation and amortization expense	344	343	315
Distributions from unconsolidated affiliates, net of earnings	21	15	14
Asset impairments	—	876	18
(Gain) loss on sale of assets, net	(19)	(42)	7
Discontinued construction projects	14	2	5
Non-controlling interest portion of depreciation and income tax	(1)	(1)	(1)
Adjusted segment EBITDA	$ 895	$ 540	$ 1,194
Logistics and Marketing segment:			
Segment net income attributable to partners (a)	$ 358	$ 273	$ 228
Non-cash commodity derivative mark-to-market	20	1	(4)
Depreciation and amortization expense	15	16	17
Distributions from unconsolidated affiliates, net of earnings	53	18	45
Asset impairments	—	9	—
Gain on sale of assets, net	(16)	—	—
Discontinued construction projects	—	—	2
Adjusted segment EBITDA	$ 430	$ 317	$ 288

(a) Includes $3 million, $8 million and $24 million in the lower of cost or market adjustments for the years ended December 31, 2016, 2015 and 2014, respectively.

Operating and Maintenance and General and Administrative Expense

Pursuant to the Contribution Agreement, on January 1, 2017, the Partnership entered into the Services and Employee Secondment Agreement (the “Services Agreement”), which replaced the services agreement between the Partnership and DCP Midstream, LLC, dated February 14, 2013, as amended. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for 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 our behalf. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf.

Operating and maintenance expenses are costs associated with the operation of a specific asset and are primarily comprised of direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services. These expenses fluctuate depending on the activities performed during a specific period.

General and administrative expense represents costs incurred to manage the business. This expense includes cost of centralized corporate functions performed by DCP Midstream, LLC, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll and engineering and all other expenses necessary or appropriate to the conduct of the business.

We also incurred third party general and administrative expenses, which were primarily related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation.

Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make estimates and assumptions. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations. These accounting policies are described further in Note 2 of the Notes to Consolidated Financial Statements in Exhibit 99.4 "Financial Statements and Supplementary Data." in this Form 8-K.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Goodwill		
We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.	We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when assigning the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	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 our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of the reporting unit, to the extent of the balance of goodwill. The two of the three reporting units that contain goodwill are not significantly impacted by the prices of commodities. Rather, they are volume based businesses that have the potential to be impacted by commodity prices should such prices remain depressed for a period of such duration that NGLs cease to be produced at levels requiring storage and distribution to end users. We did not record any goodwill impairment during the year ended December 31, 2016.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Long-Lived Assets		
We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For purposes of this evaluation, long-lived assets with recovery periods in excess of the weighted average remaining useful life of our fixed assets are further analyzed to determine if a triggering event occurred. If it is determined that a triggering event has occurred, we prepare a quantitative evaluation based on undiscounted cash flow projections expected to be realized over the remaining useful life of the primary asset. The carrying amount is not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. 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.	Our impairment analyses require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, future commodity prices, volumes, and operating costs, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. If the carrying value is not recoverable, we assess 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.	Using the impairment review methodology described herein, we have not recorded any impairment charges on long-lived assets during the year ended December 31, 2016. 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 an impairment charge. 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 this 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.
Impairment of Investments in Unconsolidated Affiliates		
We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We would then evaluate if the impairment is other than temporary.	Our impairment analyses require management to apply judgment in estimating future cash flows and asset fair values, including forecasting useful lives of the assets, assessing the probability of differing estimated outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. When there is evidence of an other than temporary loss in value, we assess the fair value of our 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.	Using the impairment review methodology described herein, we have not recorded any significant impairment charges on investments in unconsolidated affiliates during the year ended December 31, 2016. If the estimated fair value of our unconsolidated affiliates is less than the carrying value, we would recognize an impairment loss for the excess of the carrying value over the estimated fair value only if the loss is other than temporary. A period of lower commodity prices 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.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Accounting for Risk Management Activities and Financial Instruments		
Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments at fair value until the end of the contractual settlement period. 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.	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 information and the expected relationship with quoted market prices.	If our estimates of fair value are inaccurate, we may be exposed to losses or gains that could be material. A 10% difference in our estimated fair value of derivatives at December 31, 2016 would have affected net income by approximately $4 million based on our net derivative position for the year ended December 31, 2016.

Exhibit 99.4

Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM, LP CONSOLIDATED FINANCIAL STATEMENTS:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream GP, LLC
Denver, Colorado

We have audited the accompanying consolidated balance sheets of DCP Midstream, LP and subsidiaries (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Discovery Producer Services, LLC (“Discovery”), an investment of the Partnership which is accounted for by the use of the equity method (see note 10 to the consolidated financial statements). The accompanying 2016 and 2015 consolidated financial statements of the Partnership include its equity investment in Discovery of $386 million and $406 million at December 31, 2016 and 2015, respectively, and its equity earnings in Discovery of $74 million and $55 million for the years ended December 31, 2016 and 2015, respectively. The consolidated financial statements of Discovery as of December 31, 2016 and 2015 and for the years then ended, were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for the Partnership’s equity investment and equity earnings in Discovery, is based on the report of the other auditors. We have applied auditing procedures to the adjustments to reflect the Partnership’s equity investment and equity earnings in Discovery in accordance with accounting principles generally accepted in the United States of America.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of the Partnership 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 conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, the consolidated financial statements give retrospective effect to the January 1, 2017 acquisition by the Partnership of 100% of the ownership interest in the DCP Midstream Business from DCP Midstream, LLC, as a transfer of net assets between entities under common control, which has been accounted for in a manner similar to a pooling of interests.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2016, based on the criteria established in the *Internal Control -Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2017 expressed an unqualified opinion on the Partnership’s internal control over financial reporting (not presented herein).

/s/ Deloitte & Touche LLP

Denver, Colorado

February 15, 2017
(May 24, 2017 as to Notes 1, 4 and 25)

DCP MIDSTREAM, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ 3
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $4 million	652	448
Affiliates	134	75
Other	6	21
Inventories	72	51
Unrealized gains on derivative instruments	42	156
Collateral cash deposits	71	7
Other	16	43
Total current assets	994	804
Property, plant and equipment, net	9,069	9,428
Goodwill	236	242
Intangible assets, net	137	149
Investments in unconsolidated affiliates	2,969	2,992
Unrealized gains on derivative instruments	5	19
Other long-term assets	201	251
Total assets	$ 13,611	$ 13,885
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	49	38
Accrued wages and benefits	72	71
Capital spending accrual	20	20
Other	84	84
Total current liabilities	1,623	899
Long-term debt	4,907	5,669
Unrealized losses on derivative instruments	1	12
Deferred income taxes	28	26
Other long-term liabilities	199	187
Total liabilities	6,758	6,793
Commitments and contingent liabilities		
Equity:		
Predecessor equity	4,220	4,287
Limited partners (114,749,848 and 114,742,948 common units issued and outstanding, respectively)	2,591	2,762
General partner	18	18
Accumulated other comprehensive loss	(8)	(8)
Total partners' equity	6,821	7,059
Non-controlling interests	32	33
Total equity	6,853	7,092
Total liabilities and equity	$ 13,611	$ 13,885

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2016	2015	2014
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 5,317	$ 6,014	$ 11,390
Sales of natural gas, NGLs and condensate to affiliates	952	765	2,030
Transportation, processing and other	647	532	517
Trading and marketing (losses) gains, net	(23)	119	88
Total operating revenues	6,893	7,430	14,025
Operating costs and expenses:			
Purchases of natural gas and NGLs	4,978	5,563	11,363
Purchases of natural gas and NGLs from affiliates	483	418	465
Operating and maintenance expense	670	732	773
Depreciation and amortization expense	378	377	348
General and administrative expense	292	281	277
Asset impairments	—	912	18
Other (income) expense, net	(65)	10	7
(Gain) loss on sale of assets, net	(35)	(42)	7
Restructuring costs	13	11	—
Total operating costs and expenses	6,714	8,262	13,258
Operating income (loss)	179	(832)	767
Interest expense, net	(321)	(320)	(287)
Earnings from unconsolidated affiliates	282	184	82
Income (loss) before income taxes	140	(968)	562
Income tax (expense) benefit	(46)	102	(11)
Net income (loss)	94	(866)	551
Net income attributable to non-controlling interests	(6)	(5)	(4)
Net income (loss) attributable to partners	88	(871)	547
Net loss (income) attributable to predecessor operations	224	1,099	(130)
General partner’s interest in net income	(124)	(124)	(114)
Net income allocable to limited partners	$ 188	$ 104	$ 303
Net income per limited partner unit — basic and diluted	$ 1.64	$ 0.91	$ 2.84
Weighted-average limited partner units outstanding — basic and diluted	114.7	114.6	106.6

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Net income (loss)	$ 94	$ (866)	$ 551
Other comprehensive income:			
Reclassification of cash flow hedge losses into earnings	—	1	2
Total other comprehensive income	—	1	2
Total comprehensive income (loss)	94	(865)	553
Total comprehensive income attributable to non-controlling interests	(6)	(5)	(4)
Total comprehensive income (loss) attributable to partners	$ 88	$ (870)	$ 549

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Predecessor Equity	Partners' Equity: Limited Partners	Partners' Equity: General Partner	Partners' Equity: Accumulated Other Comprehensive Loss	Non-controlling Interests	Total Equity
	(Millions)					
Balance, January 1, 2016	$ 4,287	$ 2,762	$ 18	$ (8)	$ 33	$ 7,092
Net (loss) income	(224)	188	124	—	6	94
Net change in parent advances	157	—	—	—	—	157
Distributions to limited partners and general partner	—	(359)	(124)	—	—	(483)
Distributions to non-controlling interests	—	—	—	—	(7)	(7)
Balance, December 31, 2016	$ 4,220	$ 2,591	$ 18	$ (8)	$ 32	$ 6,853

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Predecessor Equity	Partners' Equity: Limited Partners	Partners' Equity: General Partner	Partners' Equity: Accumulated Other Comprehensive (Loss) Income	Non-controlling Interests	Total Equity
			(Millions)			
Balance, January 1, 2015	$ 2,189	$ 2,984	$ 18	$ (9)	$ 33	$ 5,215
Net (loss) income	(1,099)	104	124	—	5	(866)
Other comprehensive income	—	—	—	1	—	1
Net change in parent advances	3,197	—	—	—	—	3,197
Issuance of 793,080 common units to the public	—	31	—	—	—	31
Distributions to limited partners and general partner	—	(358)	(124)	—	—	(482)
Distributions to non-controlling interests	—	—	—	—	(5)	(5)
Contributions from DCP Midstream, LLC	—	1	—	—	—	1
Balance, December 31, 2015	$ 4,287	$ 2,762	$ 18	$ (8)	$ 33	$ 7,092

	Predecessor Equity	Partners' Equity: Limited Partners	Partners' Equity: General Partner	Partners' Equity: Accumulated Other Comprehensive (Loss) Income	Non-controlling Interests	Total Equity
			(Millions)			
Balance, January 1, 2014	$ 2,406	$ 1,948	$ 8	$ (11)	$ 34	$ 4,385
Net income	130	303	114	—	4	551
Other comprehensive income	—	—	—	2	—	2
Net change in parent advances	(347)	—	—	—	—	(347)
Issuance of 4,497,158 units to DCP Midstream, LLC and affiliates	—	225	—	—	—	225
Excess purchase price over carrying value of interests acquired in March 2014 Transactions	—	(178)	—	—	—	(178)
Issuance of 20,407,571 common units to the public	—	1,002	—	—	—	1,002
Distributions to limited partners and general partner	—	(316)	(104)	—	—	(420)
Distributions to non-controlling interests	—	—	—	—	(5)	(5)
Balance, December 31, 2014	$ 2,189	$ 2,984	$ 18	$ (9)	$ 33	$ 5,215

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
	(Millions)		
OPERATING ACTIVITIES:			
Net income (loss)	$ 94	$ (866)	$ 551
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	378	377	348
Earnings from unconsolidated affiliates	(282)	(184)	(82)
Distributions from unconsolidated affiliates	356	217	141
Net unrealized losses (gains) on derivative instruments	139	(46)	(43)
(Gain) loss on sale of assets	(35)	(42)	7
Asset impairments	—	912	18
Other, net	68	(68)	36
Change in operating assets and liabilities, which provided cash, net of effects of acquisitions:			
Accounts receivable	(247)	479	400
Inventories	(21)	29	16
Accounts payable	199	(381)	(467)
Other, net	(4)	15	(108)
Net cash provided by operating activities	645	442	817
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)
FINANCING ACTIVITIES:			
Proceeds from long-term debt	3,353	7,216	719
Payments of long-term debt	(3,628)	(7,196)	—
Payments of commercial paper, net	—	(1,012)	(288)
Payments of deferred financing costs	(5)	(4)	(12)
Proceeds from issuance of common units, net of offering costs	—	31	1,001
Net change in advances to predecessor from DCP Midstream, LLC	157	1,697	(301)
Distributions to limited partners and general partner	(483)	(482)	(420)
Distributions to non-controlling interests	(7)	(5)	(5)
Net cash (used in) provided by financing activities	(613)	245	694
Net change in cash and cash equivalents	(2)	(24)	(4)
Cash and cash equivalents, beginning of period	3	27	31
Cash and cash equivalents, end of period	$ 1	$ 3	$ 27

See accompanying notes to consolidated financial statements.

1. Description of Business and Basis of Presentation

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

Our Partnership includes our Gathering and Processing and Logistics and Marketing segments. For additional information regarding these segments, see Note 21 - Business Segments.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, and is 100% owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Phillips 66 and its affiliates and 50% by Enbridge, Inc. and its affiliates, or Enbridge. During the third quarter of 2016, Spectra Energy entered into an Agreement and Plan of Merger (the "Merger Agreement") with Enbridge and completed the merger during the first quarter of 2017. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. As of December 31, 2016 DCP Midstream, LLC owned approximately 21.4% of us, including limited partner and general partner interests.

On December 30, 2016, we entered into a Contribution Agreement (the “Contribution Agreement”) with DCP Midstream, LLC and DCP Midstream Operating, LP (the “Operating Partnership”), a 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. Our predecessor results consist of all of the ownership interests of DCP Midstream, LLC in all of its subsidiaries that owned operating assets ("The DCP Midstream Business"), which we acquired from DCP Midstream, LLC on January 1, 2017. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information, similar to the pooling method. Accordingly, our consolidated financial statements include the historical results of The DCP Midstream Business for all periods presented. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC’s basis in the net assets contributed. The amount of the purchase price deficit of DCP Midstream, LLC’s basis in the net assets is recognized as an addition to limited partners’ equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. Following the Transaction, DCP Midstream, LLC owned approximately 38.1% of us, including limited partner and general partner interests.

For additional information regarding the Transaction, see Note 4 - Acquisitions.

The consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries where we have the ability to exercise control. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method.

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. All 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 - We consider 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 to be cash equivalents.

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 NGLs and natural gas, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management 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. 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 in derivative instruments, with changes in 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 Derivative Activity	Mark-to-market method (a)	Net basis in trading and marketing gains and losses, net

(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, net 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 change 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 partners' equity in 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 for balance sheet purposes 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. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results 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 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 - 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.

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.

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 at the reporting unit level during 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, as well as historical and other factors, into our forecasted commodity prices. A period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill and intangible assets 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. 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 that is other than temporary, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. 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, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Long-Lived Assets - We periodically 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:

- 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 assess 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 period of lower commodity prices 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 Discount and Expense - Premiums, discounts, and expenses 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 expenses are recorded on the consolidated balance sheets within the carrying amount of long-term debt.

Non-controlling Interest - Non-controlling interest represents any third-party or affiliate interest in non-wholly owned entities that we consolidate. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our consolidated balance sheet amounts shown as non-controlling interest in equity. Distributions to and contributions from non-controlling interests represent cash payments to and cash contributions from, respectively, such third-party and affiliate investors.

Revenue Recognition - We generate the majority of our revenues from gathering, compressing, treating, processing, transporting, storing and selling of natural gas, and producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate. Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. 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:

- *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.

- *Percent-of-proceeds/index arrangements* - Under percent-of-proceeds 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 market 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 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-liquids arrangements, we do not keep any amounts related to 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 with the price of NGLs and condensate.

- *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 NGLs consists of physical purchases and sales, as well as positions in 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 to 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 commodity derivative activity 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.

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.

Purchases of natural gas and NGLs - Purchases of natural gas and NGLs represent physical purchases from suppliers.

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 and 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.

Income Taxes - We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. We owned a corporation that filed its own federal and state corporate income tax returns, which we elected to convert to a limited liability company in 2016. Our income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the master limited partnership and 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 proportionately included in the federal income tax returns of each partner.

Net Income or Loss per Limited Partner Unit - Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per limited partner unit is computed based on the weighted average number of limited partner units, plus the effect of dilutive potential units outstanding during the period using the two-class method.

3. New Accounting Pronouncements

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

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. Acquisitions

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

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

On January 1, 2015, we entered into an agreement with an affiliate of Enterprise Products Partners L.P., or Enterprise, to acquire a 15% ownership interest in Panola Pipeline Company, LLC, or Panola. At closing, we paid $1 million for our interest in the joint venture. The total consideration of approximately $26 million included our proportionate share in construction costs for expansion of the existing Panola NGL pipeline. In accordance with the Panola joint venture agreement, earnings began to accrue on February 1, 2016.

On March 31, 2014, DCP Midstream, LLC and its affiliates contributed to us: (i) a 33.33% membership interest in DCP Sand Hills Pipeline, LLC, which owns the Sand Hills pipeline; (ii) a 33.33% membership interest in DCP Southern Hills Pipeline, LLC, which owns the Southern Hills pipeline; and (iii) the remaining 20% interest in DCP SC Texas GP, or the Eagle Ford system.

On March 28, 2014, we acquired from DCP Midstream, LLC and its affiliates (i) a 35 MMcf/d cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant; and (ii) a 200 MMcf/d cryogenic natural gas processing plant also located in Weld County, Colorado, or the Lucerne 2 plant. Together with the contribution of the interests in the Sand Hills and Southern Hills pipelines and the remaining 20% interest in the Eagle Ford system, the acquisition of the Lucerne 1 and 2 plants are collectively referred to hereafter as the March 2014 Transactions.

Total consideration for the March 2014 Transactions at closing was $1,220 million, less customary working capital and other adjustments. $225 million of the consideration was funded by the issuance at closing of 2,098,674 of our common units to DCP Midstream, LLC, 1,399,116 of our common units to DCP LP Holdings, LLC, and 999,368 of our common units to DCP Midstream GP, LP. The remainder of the consideration was financed by a portion of the issuance of 14,375,000 common units to the public and the proceeds from our 5.60% 30-year Senior Notes and 2.70% five-year Senior Notes offering. The total consideration over the carrying value of the net assets of the Sand Hills and Southern Hills pipelines, the remaining 20% of the Eagle Ford system, and the Lucerne 1 and Lucerne 2 plants resulted in an excess purchase price of $178 million which was recorded as a decrease in limited partners' equity in the consolidated statement of changes in equity.

5. Dispositions

In May 2016, we entered into a purchase and sale agreement with a third party to sell our 100% interest in our 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 recorded a gain of $41 million, net of goodwill, in the third quarter of 2016.

In July 2015, we entered into a purchase and sale agreement with a third party to sell a gas processing plant and gathering system for approximately $120 million, subject to customary purchase price adjustments. This transaction closed on August 26, 2015, and we recognized a $59 million gain on sale in the consolidated statement of operations for the year ended December 31, 2015.

In May 2015, we entered into purchase and sale agreements with WTG Benedum Joint Venture to sell our 33% interest in the Benedum gas processing plant and 100% interest in the Benedum gathering system, or Benedum, for approximately $21 million, subject to customary purchase price adjustments. This transaction closed on May 13, 2015, and we recognized a $27 million loss on sale, which included $2 million of goodwill, in the consolidated statement of operations for the year ended December 31, 2015.

In January 2015, we entered into a purchase and sale agreement with Mustang Gas Products, LLC to sell our approximate 44% interest in the Dover-Hennessey gas processing plant and gathering system for approximately $29 million, subject to customary purchase price adjustments. This transaction closed on January 30, 2015, and we recognized a $10 million gain on sale in the consolidated statement of operations for the year ended December 31, 2015.

In August 2014, we entered into a purchase and sale agreement with American Midstream, LLC to divest our two-thirds ownership interest in Main Pass Oil Gathering Company, or Main Pass, for total proceeds of approximately $14 million and selling costs of approximately $3 million. This transaction closed on August 11, 2014, and we recognized a $6 million loss on sale in the consolidated statements of operations for the year ended December 31, 2014.

6. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

Pursuant to the Contribution Agreement, on January 1, 2017, the Partnership entered into the Services and Employee Secondment Agreement (the “Services Agreement”) with DCP Services, LLC, an affiliate of DCP Midstream, LLC, which replaced the services agreement between the Partnership and DCP Midstream, LLC, dated February 14, 2013, as amended. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for costs, expenses, and expenditures incurred or payments made on our behalf for general and administrative functions including, but not limited to, legal, accounting, compliance, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, benefit plan maintenance and administration, credit, payroll, internal audit, taxes and engineering, as well as salaries and benefits of seconded employees, insurance coverage and claims, capital expenditures, maintenance and repair costs and taxes. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for costs, expenses and expenditures incurred or payments made on our behalf. For the years ended December 31, 2016, 2015 and 2014, the consolidated statements of operations include employee related costs that were charged by DCP Midstream, LLC of $206 million, $224 million and $225 million, respectively within operating and maintenance expense, and $197 million, $194 million and $184 million, respectively within general and administrative expense and restructuring costs.

Phillips 66 and its Affiliates

We sell a portion of our residue gas and 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 its affiliates in the ordinary course of business.

Enbridge and its Affiliates including Spectra Energy Corp

We purchase NGLs from Enbridge and its affiliates. We anticipate continuing to purchase commodities and provide services to Enbridge and its affiliates 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 their respective operating 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 respective operating agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

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

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Year Ended December 31,		
	2016	2015	2014
	(Millions)		
Phillips 66 (including its affiliates):			
Sales of natural gas, NGLs and condensate to affiliates	$ 909	$ 695	$ 1,960
Purchases of natural gas and NGLs from affiliates	$ 18	$ —	$ 11
Operating and maintenance and general administrative expenses	$ 2	$ 4	$ 3
Enbridge (including Spectra Energy Corp.):			
Transportation, storage and processing to affiliates	$ —	$ —	$ 14
Purchases of natural gas and NGLs from affiliates	$ 33	$ 50	$ 88
Operating and maintenance and general administrative expenses	$ 4	$ 6	$ 10
Unconsolidated affiliates:			
Sales of natural gas, NGLs and condensate to affiliates	$ 43	$ 70	$ 70
Transportation, storage and processing	$ 5	$ 3	$ 12
Purchases of natural gas and NGLs from affiliates	$ 432	$ 368	$ 366

We had balances with affiliates as follows:

	December 31,	
	2016	2015
	(Millions)	
Phillips 66 (including its affiliates):		
Accounts receivable	$ 115	$ 54
Accounts payable	$ 4	$ 3
Other assets	$ 2	$ 1
Enbridge (including Spectra Energy Corp.):		
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	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 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 was $366 million, $358 million and $327 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Asset Retirement Obligations

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

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

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

(a) Asset retirement obligations are included in other long-term liabilities in the consolidated balance sheets. Accretion expense is recorded within operating and maintenance expense in our consolidated statement of operations. Accretion expense for the year ended December 31, 2014 was $6 million.

9. Goodwill and Intangible Assets

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 segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the fair value of goodwill substantially exceeded its carrying value and 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 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 volumes and commodity prices), 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.

During the second quarter of 2015, we recognized a 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 our Collbran, Michigan, and Southeast Texas reporting units. We 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 the goodwill of the Collbran reporting unit. As a result, we recorded an additional impairment of $33 million in the third quarter of 2015.

We performed our annual goodwill assessment during the quarter ended September 30, 2015. We concluded that the fair value of goodwill of our 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 our annual goodwill assessment.

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

	Year Ended December 31,					
	2016			2015		
	(Millions)					
	Gathering and Processing	Logistics and Marketing	Total	Gathering and Processing	Logistics and Marketing	Total
Balance, beginning of period	$ 170	$ 72	$ 242	$ 632	$ 72	$ 704
Impairment	—	—	—	(460)	—	(460)
Dispositions	$ (6)	$ —	$ (6)	$ (2)	$ —	$ (2)
Balance, end of period	$ 164	$ 72	$ 236	$ 170	$ 72	$ 242

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

We recorded amortization expense of $12 million, $19 million and $21 million for the years ended December 31, 2016, 2015, and 2014, respectively. As of December 31, 2016, the remaining amortization periods ranged from approximately 2 years to 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

10. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of December 31, 2016	Carrying Value as of 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 1 Fractionator	20.00%	10	11
Other	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 investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
DCP Sand Hills Pipeline, LLC	$ 110	$ 63	$ 26
Discovery Producer Services LLC	73	54	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 1 Fractionator	9	9	12
Texas Express Pipeline LLC	9	8	3
Other	2	—	—
Total earnings from unconsolidated affiliates	$ 282	$ 184	$ 82

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

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Statements of operations (a):			
Operating revenue	$ 1,311	$ 1,142	$ 859
Operating expenses	$ 539	$ 541	$ 503
Net income	$ 768	$ 600	$ 354

	December 31,	
	2016	2015
	(Millions)	
Balance sheets (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’s 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.

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.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy and are categorized in their entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.

- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the level of judgment involved in the most significant input in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third-party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

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

Interest Rate Derivative Assets and Liabilities

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

Benefits

We offer certain eligible DCP Midstream, LLC executives the opportunity to participate in our 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:

		Fair Value Measurements Using			
	Net Carrying Value	Level 1	Level 2	Level 3	Asset Impairments
			(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 measured at fair value	$ 173	$ —	$ —	$ 173	$ 912

The following table presents the financial instruments carried at fair value as of December 31, 2016 and 2015, 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 would reflect such items in the table below within the “Transfers into/out of Level 3” captions.

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
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 gains (losses) 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 gains (losses) 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/out of Level 3 for the years ended December 31, 2016 and 2015.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains or losses, 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) Represents the March 2015 novation of certain fixed price commodity derivatives.

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.

	December 31, 2016		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
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 any, and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, if any, our NGL and crude oil swaps and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which OTC broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The “prices based on models and other valuation methods” category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the specific market point.

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

The fair value of accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value.

We determine the fair value of our fixed-rate senior notes and junior subordinated notes based on quotes obtained from bond dealers. We determine the fair value of borrowings under our revolving credit facility based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of December 31, 2016 and 2015, the carrying value and fair value of our total debt, includiing current maturities, were as follows:

	December 31, 2016		December 31, 2015	
	Carrying Value (a)	Fair Value	Carrying Value (a)	Fair Value
	(Millions)			
Total debt	5,430	5,395	5,704	4,754

(a) Excludes unamortized issuance costs.

12. Debt

	December 31,	
	2016	2015
	(Millions)	
Senior notes:		
Issued November, 2012, interest at 2.500% payable semi-annually, due December, 2017	500	500
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	450	450
Issued March, 2014, interest at 2.700% payable semi-annually, due April, 2019	325	325
Issued March 2010, interest at 5.350% payable semiannually, due March 2020 (a)	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued March, 2012, interest at 4.950% payable semi-annually, due April, 2022	350	350
Issued March, 2013, interest at 3.875% payable semi-annually, due March, 2023	500	500
Issued August 2000, interest at 8.125% payable 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
Issued March, 2014, interest at 5.600% payable semi-annually, due April, 2044	400	400
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semiannually, due May 2043	550	550
Credit facilities with financial institutions:		
Revolving credit agreement terminated December, 2016, weighted average interest rate of 2.930% at December 31, 2015	—	96
Revolving credit agreement, weighted-average variable interest rate of 2.014% and 1.572%, 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	(23)	(35)
Unamortized discount	(14)	(18)
Total debt	5,407	5,669
Current maturities of long-term debt	500	—
Total long-term debt	$ 4,907	$ 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.

Credit Facilities with Financial Institutions

In May 2016, we entered into a second amendment of the DCP Midstream Amended and Restated Revolving Credit Agreement (the DCP Midstream Amended and Restated 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.

In March 2015, we entered into a first amendment of the DCP Midstream Amended and Restated Revolving Credit Agreement, which reduced the total borrowing capacity of the facility from $2.0 billion to $1.8 billion and revised the maturity date of the facility from May 2019 to March 2017. None of our physical assets were pledged as collateral for borrowings under this facility. The DCP Midstream Amended and Restated Revolving Credit Agreement was used to support our capital expansion program, for working capital requirements and other general corporate purposes, including acquisitions, as well as for letters of credit.

We have 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.

Our 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 our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate, plus 0.50% or the LIBOR Market Index rate, plus 1%, plus (b) an applicable margin of 0.45% based on our current credit rating. The Amended and Restated Credit Agreement incurs an annual facility fee of 0.3% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion Amended and Restated Credit Agreement.

As of December 31, 2016, we had unused borrowing capacity of $1,031 million, net of $24 million of letters of credit, under the Amended and Restated Credit Agreement. The financial covenants set forth in the Credit Agreement limit the Partnerships ability to incur incremental debt by $970 million as of December 31, 2016. Our 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 our Amended and Restated Credit Agreement will not become due prior to the May 1, 2019 maturity date.

The Amended and Restated Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended and Restated Credit Agreement) of not more than 5.0 to 1.0, and 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.

Senior Notes and Junior Subordinated Notes

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

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

	Debt Maturities
	(Millions)
2017	$ 500
2018	—
2019	970
2020	600
2021	500
Thereafter	2,850
	5,420
Fair value adjustments related to interest rate swap fair value hedges	24
Unamortized issuance costs	(23)
Unamortized discount	(14)
Total	$ 5,407

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.

Commodity Cash Flow Hedges

In order for our natural gas storage facility to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of our storage caverns, we may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when we bring the storage caverns into operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase base gas, the deferred losses or gains would remain in accumulated other comprehensive income, or AOCI, until the cavern is emptied and the base gas is sold. The balance in AOCI of our previously settled base gas cash flow hedges was in a loss position of $6 million as of 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. Our derivative financial instruments used to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices extend through the first quarter of 2018. The commodity derivative instruments used for our hedging programs are a combination of direct NGL product, crude oil and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we may use crude oil swaps to mitigate a portion of the commodity price risk exposure for NGLs. Historically, prices of NGLs have generally been related to crude oil prices; however, there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. The relationship of NGLs to crude oil continues to be lower than historical relationships. When our crude oil swaps become short-term in nature, certain crude oil derivatives may be converted to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange floating price risk for a fixed price. The type of instrument used to mitigate a portion of the risk may vary depending on our risk management objectives. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our consolidated statements of operations as trading and marketing (losses) 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 from 2022 through 2030 and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense, net from 2019 through 2030, the original maturity dates of the debt.

Credit Risk

Our principal customers range from large, natural gas marketers to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 27% of our NGL production was committed to Phillips 66 and CPChem as of December 31, 2016. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swaps and Derivatives Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an effective event of default under our Amended and Restated Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- Our ISDA counterparties generally have collateral thresholds of zero, requiring us to fully collateralize any commodity contracts in a net liability position, when our credit rating is below investment grade.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under other credit arrangements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Amended and Restated Credit Agreement. As of December 31, 2016, we were not a party to any agreements that would trigger the cross-default provisions.

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

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of 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 were not 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 current assets in our consolidated balance sheet, 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 on the consolidated balance sheets, regardless of our ability to net settle our positions. Instruments that are governed by agreements that include net settle provisions allow final settlement, when presented with a termination event, of outstanding amounts by extinguishing the mutual debts owed between the parties in exchange for a net amount due. We have trade receivables and payables associated with derivative instruments, subject to master netting or similar agreements, which are not included in the table below. The following summarizes the gross and net amounts of our derivative instruments:

	December 31, 2016			December 31, 2015		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount
	(Millions)					
Assets:						
Commodity derivatives	$ 47	$ —	$ 47	$ 175	$ (1)	$ 174
Liabilities:						
Commodity derivatives	$ (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)
Total	$ 47	$ 175	Total	$ (92)	$ (81)

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the year ended December 31, 2016:

	Interest Rate Derivatives	Commodity Derivatives	Foreign Currency Cash Flow Hedges (a)	Total
	(Millions)			
Net deferred (losses) gains in AOCI (beginning balance)	$ (3)	$ (6)	$ 1	$ (8)
Net deferred (losses) gains in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)

(a) Relates to Discovery, an unconsolidated affiliate.

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the year ended December 31, 2015:

	Interest Rate Cash Flow Hedges	Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
	(Millions)			
Net deferred (losses) gains in AOCI (beginning balance)	$ (4)	$ (6)	$ 1	$ (9)
Losses reclassified from AOCI to earnings — effective portion (b)	1	—	—	1
Net deferred losses in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)

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

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

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

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

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

The following tables represent, by commodity type, our net long or short 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.

	December 31, 2016			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Short Position (MMBtu)	Net (Short) Long Position (Bbls)	Net Long Position (MMBtu)
2017	(1,470,000)	(44,981,850)	(22,225,821)	6,510,000
2018	(251,000)	—	144,805	912,500
2019	(40,000)	—	(2,203)	—
2020	(50,000)	—	240,000	—

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

14. Partnership Equity and Distributions

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

During the year ended December 31, 2015, we issued 788,033 common units pursuant to our 2014 equity distribution agreement and received proceeds of $31 million, net of commissions and offering costs of less than $1 million.

In June 2014, we filed a shelf registration statement on Form S-3 with the SEC with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement allows us to issue additional common units. In September 2014, we 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 our sales agents, of common units having an aggregate offering amount of up to $500 million. During the year ended December 31, 2014, we issued 2,256,066 of our 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, we issued 14,375,000 common units to the public at $48.90 per unit. We received proceeds of $677 million, net of offering costs.

In March 2014, we issued 4,497,158 common units to DCP Midstream, LLC as partial consideration for certain transactions that closed in March 2014.

Definition of Available Cash — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash, as defined in the partnership agreement, to unitholders of record on the applicable record date, as determined by our general partner. Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by the general partner to:
    - provide for the proper conduct of our business;
    - comply with applicable law, any of our debt instruments or other agreements; and
    - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights - The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 0.3% and limited partner interest of approximately 1.7% as of December 31, 2016. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner's incentive distribution rights were not reduced as a result of our common unit issuances, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash* sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Distributions of Available Cash - Our partnership agreement, after adjustment for the general partner's relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter in the following manner:

- *first,* to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second, 13%* to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third, 23%* to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter, 48%* to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders.

The following table presents our cash distributions paid in 2016, 2015 and 2014:

Payment Date	Per Unit Distribution	Total Cash Distribution
		(Millions)
November 14, 2016	$ 0.7800	$ 120
August 12, 2016	$ 0.7800	$ 121
May 13, 2016	$ 0.7800	$ 121
February 12, 2016	$ 0.7800	$ 121
November 13, 2015	$ 0.7800	$ 120
August 14, 2015	$ 0.7800	$ 121
May 15, 2015	$ 0.7800	$ 121
February 13, 2015	$ 0.7800	$ 120
November 14, 2014	$ 0.7700	$ 117
August 14, 2014	$ 0.7575	$ 111
May 15, 2014	$ 0.7450	$ 106
February 14, 2014	$ 0.7325	$ 86

15. Equity-Based Compensation

On April 28, 2016, the unitholders of the Partnership approved the 2016 Long-Term Incentive Plan (the “2016 LTIP”), which replaced the 2005 Long-Term Incentive Plan 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.

On November 28, 2005, the board of directors of our General Partner adopted the 2005 LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 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 issued and delivered pursuant to awards under the 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner’s tax withholding obligations, are available for delivery pursuant to other awards. On February 15, 2012, the board of directors of our General Partner adopted the 2012 LTIP (the "2012 LTIP") for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The 2012 LTIP provided 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 Enbridge. The LTIPs were administered by the compensation committee of the General Partner’s board of directors through 2012, and by the General Partner’s board of directors beginning in 2013. All awards under the LTIPs are subject to cliff vesting.

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

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

Equity-based compensation expense was $18 million, $8 million and $14 million for the years ended December 31, 2016, 2015 and 2014, respectively.

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

	Vesting Period (years)	Unrecognized Compensation Expense at 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

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

16. Benefits

We do not have our own employees. The employees supporting our operations are employees of DCP Midstream, LLC, for which we incur charges under the Services Agreement. All DCP Midstream, LLC employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in the 401(k) and retirement plan, to which a range of 4% to 7% of each eligible employee's qualified earnings is contributed to the retirement plan, based on years of service. Effective on January 1, 2015, DCP Midstream, LLC 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, DCP Midstream, LLC matches 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.

DCP Midstream, LLC offers 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.

17. Net Income or Loss per Limited Partner Unit

Our net income or loss is allocated to the general partner and the limited partners in accordance with their respective ownership percentages, after allocating Available Cash generated during the period in accordance with our Partnership agreement.

Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the Partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

These required disclosures do not impact our overall net income or loss or other financial results; however, in periods in which aggregate net income exceeds our Available Cash it will have the impact of reducing net income per LPU.

Basic and diluted net income or loss per LPU is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per LPU is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding awards under the LTIP. The dilutive effect of unit-based awards was 1,105, 7,038 and 10,574 equivalent units during the years ended December 31, 2016, 2015 and 2014 respectively.

18. Income Taxes

We are structured as a master limited partnership with sufficient qualifying income, which is a pass-through entity for federal income tax purposes. We owned a corporation that filed its own federal, foreign and state corporate income tax returns. During the year ended December 31, 2016, we elected to convert the corporation to a limited liability company for federal income tax purposes. The income tax (expense) benefit related to this corporation is included in our income tax (expense) benefit, along with state and local taxes of the limited liability entities.

Income tax (expense) benefit consists 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	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 being structured as a master limited partnership, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states, primarily Texas. The State of Texas imposes a margin tax that is assessed at 0.75%, 0.75%, and 0.95%, of taxable margin apportioned to Texas for the years ended December 31, 2016, 2015 and 2014, respectively.

19. Commitments and Contingent Liabilities

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

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

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

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

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 combined balance sheets as other current liabilities were $4 million and $3 million, respectively. As of December 31, 2016 and 2015, environmental liabilities included in our combined balance sheets as other long-term liabilities was $9 million.

Other Commitments and Contingencies — We utilize assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, totaled $37 million, $34 million, and $31 million for 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 at December 31, 2016:

	(Millions)
2017	$ 61
2018	37
2019	35
2020	29
2021	21
Thereafter	42
Total minimum rental payments	$ 225

20. 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 their 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 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 in the consolidated statement of operations for the year ended December 31, 2015.

21. Business Segments

Concurrent with the completion of the Transaction in the first quarter of 2017, management reevaluated our reportable segments and determined that our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Segment information for prior periods has been retrospectively adjusted to furnish comparative information similar to the pooling method to reflect these reportable segments. These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Our Gathering and Processing reportable segment includes operating segments that have been aggregated based on the nature of the products and services provided. Gross margin is a performance measure utilized by management to monitor the operations of each segment.

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

Year Ended December 31, 2016:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 4,490	$ 6,186	$ —	$ (3,783)	$ 6,893
Gross margin (a)	$ 1,227	$ 205	$ —	$ —	$ 1,432
Operating and maintenance expense	(611)	(43)	(16)	—	(670)
Depreciation and amortization expense	(344)	(15)	(19)	—	(378)
General and administrative expense	(14)	(9)	(269)	—	(292)
Other income (expense), net	73	(5)	(3)	—	65
Earnings from unconsolidated affiliates	73	209	—	—	282
Interest expense, net	—	—	(321)	—	(321)
Gain on sale of assets, net	19	16	—	—	35
Restructuring costs	—	—	(13)	—	(13)
Income tax expense	—	—	(46)	—	(46)
Net income (loss)	$ 423	$ 358	$ (687)	$ —	$ 94
Net income attributable to non-controlling interests	(6)	—	—	—	(6)
Net income (loss) attributable to partners	$ 417	$ 358	$ (687)	$ —	$ 88
Non-cash derivative mark-to-market (b)	$ (119)	$ (20)	$ —	$ —	$ (139)
Non-cash lower of cost or market adjustments	$ —	$ 3	$ —	$ —	$ 3
Capital expenditures	$ 107	$ 10	$ 27	$ —	$ 144
Investments in unconsolidated affiliates, net	$ 1	$ 52	$ —	$ —	$ 53

Year Ended December 31, 2015:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 4,910	$ 6,487	$ —	$ (3,967)	$ 7,430
Gross margin (a)	$ 1,213	$ 236	$ —	$ —	$ 1,449
Operating and maintenance expense	(668)	(49)	(15)	—	(732)
Depreciation and amortization expense	(343)	(16)	(18)	—	(377)
General and administrative expense	(22)	(11)	(248)	—	(281)
Other expense, net	(1)	(8)	(1)	—	(10)
Asset impairment	(876)	(9)	(27)	—	(912)
Earnings from unconsolidated affiliates	54	130	—	—	184
Interest expense, net	—	—	(320)	—	(320)
Gain on sale of assets, net	42	—	—	—	42
Restructuring costs	—	—	(11)	—	(11)
Income tax benefit	—	—	102	—	102
Net income (loss)	$ (601)	$ 273	$ (538)	$ —	$ (866)
Net income attributable to non-controlling interests	(5)	—	—	—	(5)
Net income (loss) attributable to partners	$ (606)	$ 273	$ (538)	$ —	$ (871)
Non-cash derivative mark-to-market (b)	$ 47	$ (1)	$ —	$ —	$ 46
Non-cash lower of cost or market adjustments	$ —	$ 8	$ —	$ —	$ 8
Capital expenditures	$ 729	$ 52	$ 30	$ —	$ 811
Investments in unconsolidated affiliates, net	$ 15	$ 49	$ —	$ —	$ 64

Year Ended December 31, 2014:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 9,873	$ 12,649	$ —	$ (8,497)	$ 14,025
Gross margin (a)	$ 1,971	$ 226	$ —	$ —	$ 2,197
Operating and maintenance expense	(725)	(44)	(4)	—	(773)
Depreciation and amortization expense	(315)	(17)	(16)	—	(348)
General and administrative expense	(27)	(14)	(236)	—	(277)
Other expense, net	(5)	—	(2)	—	(7)
Asset impairment	(18)	—	—	—	(18)
Earnings from unconsolidated affiliates	5	77	—	—	82
Interest expense, net	—	—	(287)	—	(287)
Loss on sale of assets, net	(7)	—	—	—	(7)
Income tax expense	—	—	(11)	—	(11)
Net income (loss)	$ 879	$ 228	$ (556)	$ —	$ 551
Net income attributable to non-controlling interests	(4)	—	—	—	(4)
Net income (loss) attributable to partners	$ 875	$ 228	$ (556)	$ —	$ 547
Non-cash derivative mark-to-market (b)	$ 39	$ 4	$ —	$ —	$ 43
Non-cash lower of cost or market adjustments	$ —	$ 24	$ —	$ —	$ 24
Capital expenditures	$ 1,272	$ 62	$ 50	$ —	$ 1,384
Investments in unconsolidated affiliates, net	$ 75	$ 86	$ —	$ —	$ 161

	December 31, 2016	December 31, 2015
	(Millions)	
Segment long-term assets:		
Gathering and Processing	$ 9,053	$ 9,431
Logistics and Marketing	3,278	3,339
Other (c)	286	311
Total long-term assets	12,617	13,081
Current assets	994	804
Total assets	$ 13,611	$ 13,885

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

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

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

22. Supplemental Cash Flow Information

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

23. Quarterly Financial Data (Unaudited)

Our consolidated results of operations by quarter for the years ended December 31, 2016 and 2015 were as follows (millions, except per unit amounts):

2016	First	Second	Third	Fourth	Year Ended December 31, 2016
Total operating revenues	$ 1,464	$ 1,623	$ 1,823	$ 1,983	$ 6,893
Operating income (loss)	$ 80	$ (12)	$ 92	$ 19	$ 179
Net income (loss)	$ 65	$ (21)	$ 89	$ (39)	$ 94
Net income attributable to non-controlling interests	$ —	$ (1)	$ —	$ (5)	$ (6)
Net income attributable to partners	$ 65	$ (22)	$ 89	$ (44)	$ 88
Net loss attributable to predecessor operations	$ (7)	$ (67)	$ (31)	$ (119)	$ (224)
Net income allocable to limited partners	$ 41	$ 14	$ 89	$ 44	$ 188
Basic and diluted net income per limited partner unit	$ 0.36	$ 0.12	$ 0.78	$ 0.38	$ 1.64

2015	First	Second	Third	Fourth	Year Ended December 31, 2015
Total operating revenues	$ 2,020	$ 1,849	$ 1,870	$ 1,691	$ 7,430
Operating income (loss)	$ 40	$ (463)	$ 57	$ (466)	$ (832)
Net (loss) income	$ (17)	$ (491)	$ 24	$ (382)	$ (866)
Net income attributable to non-controlling interests	$ —	$ —	$ (1)	$ (4)	$ (5)
Net income attributable to partners	$ (17)	$ (491)	$ 23	$ (386)	$ (871)
Net loss attributable to predecessor operations	$ (86)	$ (489)	$ (48)	$ (476)	$ (1,099)
Net income (loss) allocable to limited partners	$ 38	$ (33)	$ 40	$ 59	$ 104
Basic and diluted net income (loss) per limited partner unit	$ 0.33	$ (0.29)	$ 0.35	$ 0.51	$ 0.91

24. Supplementary Information — Condensed Consolidating Financial Information

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

Condensed Consolidating Balance Sheet
December 31, 2016

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

	Condensed Consolidating Balance Sheet December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ —	$ 3	$ —	$ 3
Accounts receivable, net	—	—	544	—	544
Inventories	—	—	51	—	51
Other	—	—	206	—	206
Total current assets	—	—	804	—	804
Property, plant and equipment, net	—	—	9,428	—	9,428
Goodwill and intangible assets, net	—	—	391	—	391
Advances receivable — consolidated subsidiaries	3,436	3,353	—	(6,789)	—
Investments in consolidated subsidiaries	3,623	6,011	—	(9,634)	—
Investments in unconsolidated affiliates	—	—	2,992	—	2,992
Other long-term assets	—	—	270	—	270
Total assets	$ 7,059	$ 9,364	$ 13,885	$ (16,423)	$ 13,885
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 72	$ 827	$ —	$ 899
Advances payable — consolidated subsidiaries		—	6,789	(6,789)	—
Long-term debt	—	5,669	—	—	5,669
Other long-term liabilities	—	—	225	—	225
Total liabilities	—	5,741	7,841	(6,789)	6,793
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	7,059	3,626	6,016	(9,634)	7,067
Accumulated other comprehensive loss	—	(3)	(5)	—	(8)
Total partners' equity	7,059	3,623	6,011	(9,634)	7,059
Non-controlling interests	—	—	33	—	33
Total equity	7,059	3,623	6,044	(9,634)	7,092
Total liabilities and equity	$ 7,059	$ 9,364	$ 13,885	$ (16,423)	$ 13,885

Condensed Consolidating Statement of Operations
Year Ended December 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 6,269	$ —	$ 6,269
Transportation, processing and other	—	—	647	—	647
Trading and marketing losses, net	—	—	(23)	—	(23)
Total operating revenues	—	—	6,893	—	6,893
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	5,461	—	5,461
Operating and maintenance expense	—	—	670	—	670
Depreciation and amortization expense	—	—	378	—	378
General and administrative expense	—	—	292	—	292
Other income, net	—	—	(65)	—	(65)
Restructuring costs	—	—	13		13
Gain on sale of assets, net	—	—	(35)	—	(35)
Total operating costs and expenses	—	—	6,714	—	6,714
Operating income	—	—	179	—	179
Interest expense, net	—	(321)	—	—	(321)
Income from consolidated subsidiaries	88	409	—	(497)	—
Earnings from unconsolidated affiliates	—	—	282	—	282
Income before income taxes	88	88	461	(497)	140
Income tax expense	—	—	(46)	—	(46)
Net income	88	88	415	(497)	94
Net income attributable to non-controlling interests	—	—	(6)	—	(6)
Net income attributable to partners	$ 88	$ 88	$ 409	$ (497)	$ 88

Condensed Consolidating Statement of Comprehensive Income
Year Ended December 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 88	$ 88	$ 415	$ (497)	$ 94
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	—	—	—	—
Other comprehensive income from consolidated subsidiaries	—	—	—	—	—
Total other comprehensive income	—	—	—	—	—
Total comprehensive income	88	88	415	(497)	94
Total comprehensive income attributable to non-controlling interests	—	—	(6)	—	(6)
Total comprehensive income attributable to partners	$ 88	$ 88	$ 409	$ (497)	$ 88

Condensed Consolidating Statement of Operations
Year Ended December 31, 2015

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 6,779	$ —	$ 6,779
Transportation, processing and other	—	—	532	—	532
Trading and marketing gains, net	—	—	119	—	119
Total operating revenues	—	—	7,430	—	7,430
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	5,981	—	5,981
Operating and maintenance expense	—	—	732	—	732
Depreciation and amortization expense	—	—	377	—	377
General and administrative expense	—	—	281	—	281
Asset impairments	—	—	912	—	912
Other expense, net	—	—	10	—	10
Restructuring costs	—	—	11	—	11
Gain on sale of assets, net	—	—	(42)	—	(42)
Total operating costs and expenses	—	—	8,262	—	8,262
Operating loss	—	—	(832)	—	(832)
Interest expense, net	—	(320)	—	—	(320)
Loss from consolidated subsidiaries	(871)	(551)	—	1,422	—
Earnings from unconsolidated affiliates	—	—	184	—	184
Loss before income taxes	(871)	(871)	(648)	1,422	(968)
Income tax benefit	—	—	102	—	102
Net loss	(871)	(871)	(546)	1,422	(866)
Net income attributable to non-controlling interests	—	—	(5)	—	(5)
Net loss attributable to partners	$ (871)	$ (871)	$ (551)	$ 1,422	$ (871)

Condensed Consolidating Statement of Comprehensive Income
Year Ended December 31, 2015

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net loss	$ (871)	$ (871)	$ (546)	$ 1,422	$ (866)
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	1	—	—	1
Other comprehensive income from consolidated subsidiaries	1	—	—	(1)	—
Total other comprehensive income	1	1	—	(1)	1
Total comprehensive loss	(870)	(870)	(546)	1,421	(865)
Total comprehensive loss attributable to non-controlling interests	—	—	(5)	—	(5)
Total comprehensive loss attributable to partners	$ (870)	$ (870)	$ (551)	$ 1,421	$ (870)

	Condensed Consolidating Statement of Operations Year Ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 13,420	$ —	$ 13,420
Transportation, processing and other	—	—	517	—	517
Trading and marketing gains, net	—	—	88	—	88
Total operating revenues	—	—	14,025	—	14,025
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	11,828	—	11,828
Operating and maintenance expense	—	—	773	—	773
Depreciation and amortization expense	—	—	348	—	348
General and administrative expense	—	—	277	—	277
Asset impairments	—	—	18	—	18
Other expense, net	—	—	7	—	7
Loss on sale of assets, net	—	—	7	—	7
Total operating costs and expenses	—	—	13,258	—	13,258
Operating income	—	—	767	—	767
Interest expense, net	—	(287)	—	—	(287)
Earnings from unconsolidated affiliates	—	—	82	—	82
Income from consolidated subsidiaries	547	834	—	(1,381)	—
Income before income taxes	547	547	849	(1,381)	562
Income tax expense	—	—	(11)	—	(11)
Net income	547	547	838	(1,381)	551
Net income attributable to non-controlling interests	—	—	(4)	—	(4)
Net income attributable to partners	$ 547	$ 547	$ 834	$ (1,381)	$ 547

	Condensed Consolidating Statement of Comprehensive Income Year Ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 547	$ 547	$ 838	$ (1,381)	$ 551
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	2	—	—	2
Other comprehensive income from consolidated subsidiaries	2	—	—	(2)	—
Total other comprehensive income	2	2	—	(2)	2
Total comprehensive income	549	549	838	(1,383)	553
Total comprehensive income attributable to non-controlling interests	—	—	(4)	—	(4)
Total comprehensive income attributable to partners	$ 549	$ 549	$ 834	$ (1,383)	$ 549

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (305)	$ 950	$ —	$ 645
INVESTING ACTIVITIES:					
Intercompany transfers	483	585	—	(1,068)	—
Capital expenditures	—	—	(144)	—	(144)
Investments in unconsolidated affiliates, net	—	—	(53)	—	(53)
Proceeds from sale of assets	—	—	163	—	163
Net cash provided by (used in) investing activities	483	585	(34)	(1,068)	(34)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(1,068)	1,068	—
Proceeds from long-term debt	—	3,353	—	—	3,353
Payments of long-term debt	—	(3,628)	—	—	(3,628)
Payments of deferred financing costs	—	(5)	—	—	(5)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	157	—	157
Distributions to limited partners and general partner	(483)	—	—	—	(483)
Distributions to non-controlling interests	—	—	(7)	—	(7)
Net cash used in financing activities	(483)	(280)	(918)	1,068	(613)
Net change in cash and cash equivalents	—	—	(2)	—	(2)
Cash and cash equivalents, beginning of period	—	—	3	—	3
Cash and cash equivalents, end of period	$ —	$ —	$ 1	$ —	$ 1

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (311)	$ 753	$ —	$ 442
INVESTING ACTIVITIES:					
Intercompany transfers	(1,049)	1,283	—	(234)	—
Capital expenditures	—	—	(811)	—	(811)
Investments in unconsolidated affiliates, net	—	—	(64)	—	(64)
Proceeds from sale of assets	—	—	164	—	164
Net cash (used in) provided by investing activities	(1,049)	1,283	(711)	(234)	(711)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(234)	234	—
Proceeds from long-term debt	—	7,216	—	—	7,216
Payments of long-term debt	—	(7,196)	—	—	(7,196)
Payments of commercial paper, net	—	(1,012)	—	—	(1,012)
Payment of deferred financing costs	—	(4)	—	—	(4)
Proceeds from issuance of common units, net of offering costs	31	—	—	—	31
Net change in advances to predecessor from DCP Midstream, LLC	1,500	—	197	—	1,697
Distributions to limited partners and general partner	(482)	—	—	—	(482)
Distributions to non-controlling interests	—		(5)	—	(5)
Net cash provided by (used in) financing activities	1,049	(996)	(42)	234	245
Net change in cash and cash equivalents	—	(24)	—	—	(24)
Cash and cash equivalents, beginning of period	—	24	3	—	27
Cash and cash equivalents, end of period	$ —	$ —	$ 3	$ —	$ 3

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (271)	$ 1,088	$ —	$ 817
INVESTING ACTIVITIES:					
Intercompany transfers	(581)	(141)	—	722	—
Capital expenditures	—	—	(1,384)	—	(1,384)
Investments in unconsolidated affiliates, net	—	—	(161)	—	(161)
Proceeds from sale of assets	—	—	30	—	30
Net cash used in investing activities	(581)	(141)	(1,515)	722	(1,515)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	722	(722)	—
Proceeds from long-term debt	—	719	—	—	719
Payments of issuance of commercial paper, net	—	(288)	—	—	(288)
Payment of deferred financing costs	—	(12)	—	—	(12)
Proceeds from issuance of common units, net of offering costs	1,001	—	—	—	1,001
Distributions to limited partners and general partner	(420)	—	—	—	(420)
Distributions to non-controlling interests	—	—	(5)	—	(5)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(301)	—	(301)
Net cash provided by financing activities	581	419	416	(722)	694
Net change in cash and cash equivalents	—	7	(11)	—	(4)
Cash and cash equivalents, beginning of year	—	17	14	—	31
Cash and cash equivalents, end of year	$ —	$ 24	$ 3	$ —	$ 27

25. Subsequent Events

On December 30, 2016, we entered into a Contribution Agreement with DCP Midstream, LLC and DCP Midstream Operating, LP. The Transaction closed effective January 1, 2017. For additional information regarding the Transaction, see Note 4 - Acquisitions.

Effective January 11, 2017, we changed our name to "DCP Midstream, LP" from "DCP Midstream Partners, LP" (the Name Change").

In connection with the Name Change, the ticker symbol for our common units representing limited partner interests listed on the NYSE changed from “DPM” to “DCP” effective at the open of the NYSE on January 23, 2017.

On January 26, 2017, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit. The distribution was paid 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.

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

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

On May 17, 2017, we announced the planned divestiture of our Douglas gathering system in Wyoming, which includes approximately 1,500 miles of gathering lines for approximately $128 million, subject to customary closing adjustments. The transaction is expected to close on or before the end of the second quarter.

Exhibit 99.5

Certain Relationships and Related Transactions, and Director Independence

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation, and liquidation. These distributions and payments are determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage:	
Distributions of Available Cash to our General Partner and its affiliates	We will generally make cash distributions to the unitholders and to our General Partner, in accordance with their pro rata interest. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level.
Payments to our General Partner and its affiliates	For further information regarding payments to our General Partner, please see the "Services Agreement" section below.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage:	
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Contribution Agreement

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

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

Our General Partner and its affiliates will also receive payments from us pursuant to the contractual arrangements described below under the caption "Contracts with Affiliates."

The Services Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Services Agreement will also terminate in the event of a change of control of us, our General Partner or DCP Midstream, LLC.

Competition

None of DCP Midstream, LLC, or any of its affiliates, including Phillips 66 and Enbridge, is restricted, under either the partnership agreement or the Services Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Phillips 66 and Enbridge, 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.

Contracts with Affiliates

We sell a portion of our residue gas and NGLs to, and purchase NGLs from, Phillips 66 and its respective affiliates. We anticipate continuing to purchase and sell these commodities to Phillips 66 and its respective affiliates in the ordinary course of business.

We purchase natural gas and NGLs from Enbridge and its affiliates. We anticipate continuing to purchase these commodities from Enbridge and its affiliates in the ordinary course of business.

Unconsolidated Affiliates

Under the terms of their respective operating 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 respective operating agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

Transportation Arrangements

The Texas Express, Front Range, Sand Hills and Southern Hills pipelines have in place 15-year transportation agreements, commencing at the pipelines' respective in-service dates, with us pursuant to which we have committed to transport minimum throughput volumes at rates defined in each respective pipeline’s tariffs.

Review, Approval or Ratification of Transactions with Related Persons

Our partnership agreement contains specific provisions that address potential conflicts of interest between the owner of our general partner and its affiliates, including DCP Midstream, LLC on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our general partner will resolve the conflict. Our general partner may, but is not required to, seek the approval of such resolution from the special committee of the board of directors of our general partner, which committee is comprised of independent directors and acts as our conflicts committee. The partnership agreement provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or to our unitholders if the resolution of the conflict is:

- approved by the conflicts committee;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner does not seek approval from the special committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in the best interests of the Partnership, unless the context otherwise requires.

In addition, our code of business ethics requires that all employees, including employees of affiliates of DCP Midstream, LLC who perform services for us and our general partner, avoid or disclose any activity that may interfere, or have the appearance of interfering, with their responsibilities to us.

Director Independence

Please see Item 10. “Directors, Executive Officers and Corporate Governance” in the 2016 Form 10-K for information about the independence of our general partner’s board of directors and its committees, which information is incorporated herein by reference in its entirety.