

2017  
ANNUAL REPORT

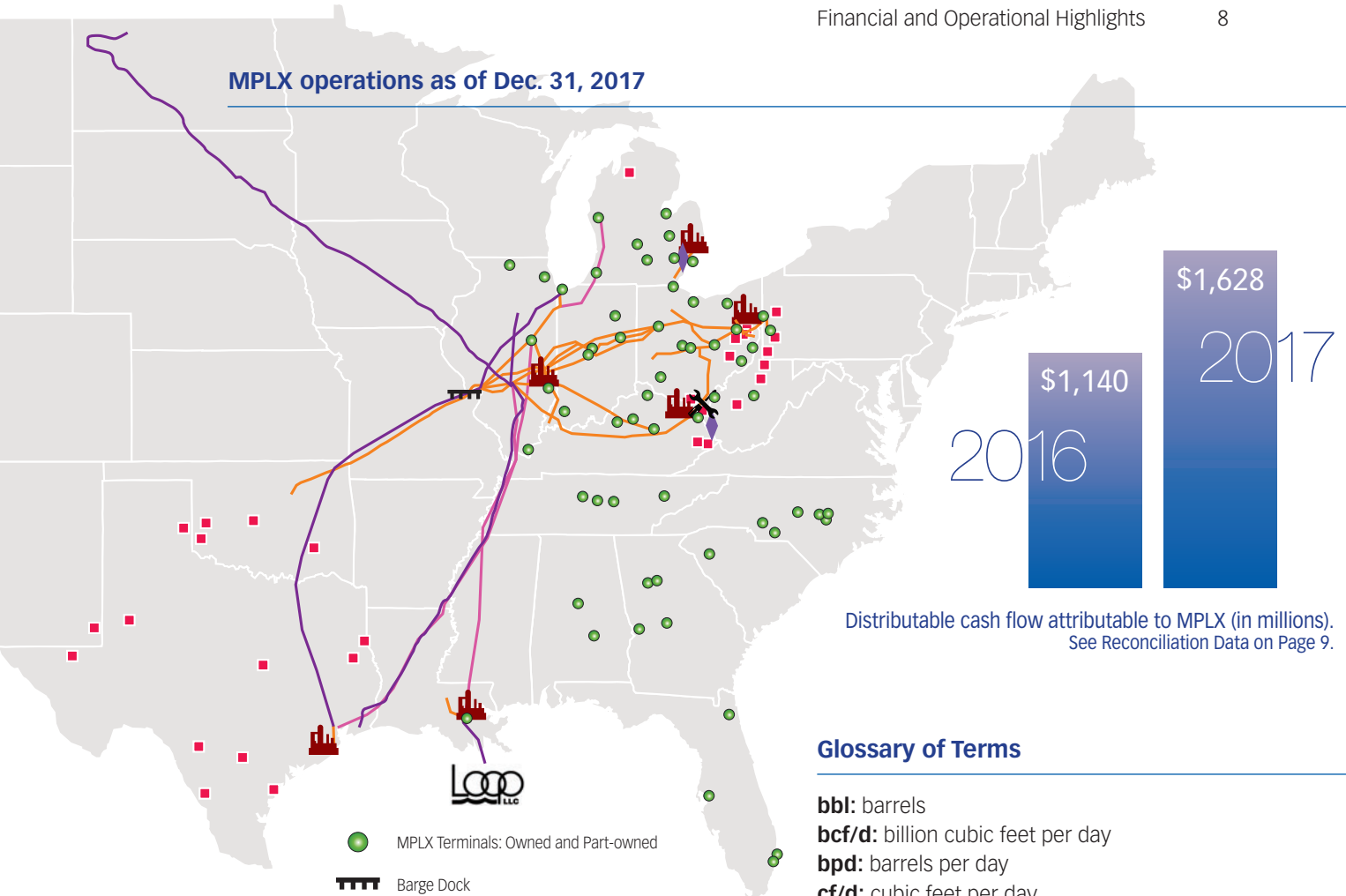


Cover: An MPLX marine vessel, acquired in 2016 as part of a dropdown transaction with MPC, loads at MPLX dock facilities on the Mississippi River at Wood River, Illinois

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### MPLX operations as of Dec. 31, 2017



Distributable cash flow attributable to MPLX (in millions).  
See Reconciliation Data on Page 9.

## Glossary of Terms

- bbbl**: barrels
- bcf/d**: billion cubic feet per day
- bpd**: barrels per day
- cf/d**: cubic feet per day
- EBITDA**: earnings before interest, taxes, depreciation and amortization
- GP**: general partner
- IPO**: initial public offering of units
- LP**: limited partner
- MarkWest**: MarkWest Energy Partners, L.P., is a wholly owned subsidiary of MPLX LP acquired in December 2015
- mbpd**: thousand barrels per day
- MLP**: master limited partnership
- mmcf/d**: million cubic feet per day
- MPC**: Marathon Petroleum Corporation
- MPL**: Marathon Pipe Line LLC
- NGL**: Natural gas liquids

- MPLX Terminals: Owned and Part-owned
- Barge Dock
- Cavern
- MPLX Pipelines: Owned & Operated
- MPLX Interest Pipelines: Operated by Others
- MPLX Operated Pipelines: Owned by Others
- MarkWest Complex
- Marine Repair Facility
- MPC Refineries

## FROM THE CHAIRMAN AND CEO

Fellow unitholders,

MPLX delivered strong performance in 2017, including record financial and operational results. We gathered, processed and fractionated record gas and NGL volumes, and more than tripled our net income to \$794 million for the year. Our adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) increased \$585 million, to more than \$2 billion, and our full-year distributable cash flow exceeded \$1.6 billion.



We delivered distribution growth of 12.1 percent and affirmed a 2018 distribution growth target of 10 percent. Since our IPO in 2012, we have achieved 20 consecutive quarters of increased cash distributions for our unitholders, representing a compound annual growth rate of 18.3 percent over the minimum quarterly distribution established when we formed MPLX.

During our five years as a publicly traded partnership, we have transformed our asset base and earnings profile. In late 2015, we expanded into the midstream natural gas business with the addition of MarkWest. And early last year, we announced a strategic action plan to enhance unitholder value, which we completed on Feb. 1, 2018.

As part of these strategic actions, we acquired assets and services from our sponsor, Marathon Petroleum Corporation, that are projected to generate approximately \$1.4 billion in annual EBITDA. MPC also exchanged its general partner economic interest in MPLX, including incentive distribution rights, for newly issued MPLX common units.

### 2017 Success by the Numbers

<i>In millions, except per unit and ratio data</i>	2017	2016
Net income attributable to MPLX <sup>(a)</sup>	\$ 794	\$ 233
Adjusted EBITDA attributable to MPLX <sup>(b)</sup>	2,004	1,419
Net cash provided by operating activities	1,907	1,491
Distributable cash flow (DCF) <sup>(b)</sup>	1,628	1,140
Distribution per common unit <sup>(c)</sup>	2.2975	2.05
Distribution coverage ratio <sup>(d)</sup>	1.28x	1.23x
Growth capital expenditures <sup>(e)</sup>	1,518	1,292

(a) The year ended Dec. 31, 2016, includes pretax, non-cash impairments of \$89 million related to an equity method investment and \$130 million related to the goodwill established in connection with the MarkWest acquisition.

(b) Non-GAAP measure calculated before the distribution to preferred units and excluding impairment charges. See Reconciliation Data on Page 9.

(c) Distributions declared by the board of directors of our general partner.

(d) See description in Non-GAAP Financial Measures on back cover.

(e) Excludes non-affiliated joint-venture (JV) members' share of Capital Expenditures. See Capital Expenditures table on Page 10.

## FROM THE CHAIRMAN AND CEO

These transactions have nearly doubled the partnership's earnings base, improved our cost of capital, and added high-quality, fee-based revenue streams that further diversify our earnings.

In 2017, we also welcomed Mike Hennigan to the MPLX executive team as president. With 35 years in the energy industry, Mike brings a tremendous depth of experience to the partnership. We have benefited greatly from his skill and vision, and we are fortunate to have his expertise as we continue to grow.

We are enthusiastic about the future of MPLX. We are now one of the largest diversified master limited partnerships in the energy sector. We have a robust portfolio of organic projects in some of the most prolific and economic shale plays in the nation, and a high-quality suite of transportation and storage assets. Along with our ongoing commitment to maintain a strong balance sheet and an investment-grade credit profile, these factors position us to deliver long-term, sustainable growth for our investors.

Sincerely,



Gary R. Heminger  
Chairman and Chief Executive Officer

Below:  
Dock facilities at MPC's  
Galveston Bay refinery



## LOGISTICS & STORAGE

In 2017, MPLX's Logistics and Storage segment, which generates stable cash flows with its fee-based revenues, reported segment operating income of \$782 million.

During the year, the Logistics and Storage segment continued executing its long-term strategy to expand crude oil and refined products infrastructure, acquiring the Ozark Pipeline; purchasing an indirect equity interest in the Bakken Pipeline system; fully commissioning the Utica Build-Out projects, including the Harpster-to-Lima Pipeline; and beginning the expansion of the Ozark and Wood River-to-Patoka pipeline systems, which connect Cushing, Oklahoma, to Patoka, Illinois.

Additionally, through the strategic actions executed with our sponsor, MPC, completed in February 2018, the partnership acquired terminals, pipelines and storage assets in March; joint-interest ownership in certain pipeline and storage assets in September; and, in a transaction that closed on Feb. 1, 2018, fuels distribution services and refining logistics assets. Combined, these additional assets and services are projected to generate approximately \$1.4 billion in annual EBITDA, transforming the segment and the partnership.

MPLX continues to expand the logistics and storage services it provides to MPC, including butane caverns and tank farms. And with the acquisition of docks supporting MPC's operations, it plans to continue the export-capacity expansion project already underway at the Galveston Bay refinery.

Bottom right:  
Laying the Harpster-  
to-Lima Pipeline



## GATHERING & PROCESSING

MPLX's Gathering and Processing segment delivered strong volume growth in 2017 and continues to provide exceptional organic growth opportunities, with a robust portfolio of organic projects in the Marcellus, Utica, Permian and STACK (Sooner Trend of the Anadarko Basin Canadian and Kingfisher counties), which are among the most prolific and economic shale plays in the country.

We achieved record volumes, including increases of 10 percent in gathering throughput, 12 percent in natural gas processing and 18 percent in natural gas liquids fractionation volumes for the year. During 2017, we added 400 million cubic feet per day of processing capacity and 120,000 barrels per day of fractionation capacity.

The partnership continues to pursue and execute significant growth opportunities. In the Marcellus basin, we initiated the startup of the Sherwood IX gas processing plant as we closed 2017, and two new plants are planned for our Sherwood complex in 2018, consistent with our strategy of constructing plants on a just-in-time basis. We also expect to complete plant additions at our Houston, Majorsville and Harmon Creek complexes by the end of the year. The addition of these plants will increase the



Above: Sherwood gas processing complex in West Virginia

## GATHERING & PROCESSING

partnership's processing capacity in the Marcellus and Utica basins by 21 percent to over 7 billion cubic feet per day, further strengthening our position as the largest processor in the Northeast.

MPLX is also growing its footprint in prolific resource plays in the Southwest. In the Delaware Basin of West Texas, our Hidalgo gas processing plant operated near full utilization in 2017. To support ongoing producer activity in this area, we built a second gas processing plant, named Argo, which was placed in service in the first quarter of 2018. In addition, the partnership is constructing a gas processing plant in the STACK resource of Oklahoma's Cana-Woodford Shale that is expected to be complete by mid-2018. We are also investing in two additional plants in southeast Oklahoma through our Centrahoma processing joint venture.

Overall, in 2018 we plan to add eight processing plants, increasing the partnership's processing capacity by nearly 1.5 billion cubic feet per day. The partnership also expects to add 40,000 barrels per day of ethane fractionation capacity, and 60,000 barrels per day of propane-plus fractionation capacity.

Below:  
Hidalgo gas  
processing plant  
in Texas



increasing processing capacity

## BOARD OF DIRECTORS



## Standing, left to right

**Pamela K.M. Beall**

Executive vice president and chief financial officer, MPLX GP LLC. Ms. Beall began her career with Marathon Oil Co. and transferred to USX Corporation. After rejoining Marathon in 2002, she held various leadership positions, most recently executive vice president, Corporate Planning and Strategy, MPLX GP LLC.

**Frank M. Semple**

Retired chairman, president and CEO, MarkWest Energy Partners, L.P. Mr. Semple joined MarkWest in 2003 as president and CEO, and was elected chairman in 2008. He completed a 22-year career with The Williams Cos. and WilTel Communications prior to MarkWest.

**David A. Daberko**

Retired chairman, National City Corp. Lead Director, MPC. Mr. Daberko joined National City Bank in 1968 and went on to hold a number of management positions. He was named chairman of the board and chief executive officer of National City Corporation in 1995 and served in those capacities until his retirement in 2007.

**Donald C. Templin**

President, MPC. Mr. Templin was appointed senior vice president and chief financial officer of MPC in 2011 and vice president and chief financial officer of MPLX GP LLC in 2012. He was named executive vice president of MPC and president of MPLX in 2016. He assumed his current role in 2017. Prior to joining MPC in 2011, Mr. Templin was managing partner of PricewaterhouseCoopers LLP's audit practice in Georgia, Alabama and Tennessee.

**Christopher A. Helms**

President and CEO, U.S. Shale Management Co. Mr. Helms previously served in various leadership positions at NiSource Inc. and NiSource Gas Transmission and Storage. Mr. Helms was responsible for leading the company's interstate gas transmission, storage and midstream businesses.

**Michael L. Beatty**

Former chairman, Beatty & Wozniak, P.C. Mr. Beatty was a director of MarkWest Hydrocarbon and was named a director of MarkWest Energy Partners, L.P. in 2008. Prior to these positions, he was executive vice president, general counsel and director of the Coastal Corp., and chief of staff to Colorado Gov. Roy Romer.

**Garry L. Peiffer**

Retired president, MPLX GP LLC, and retired executive vice president, Corporate Planning and Investor and Government Relations, MPC. Mr. Peiffer joined Marathon Oil Co. in 1974 and held various leadership positions with the company. He was named executive vice president of MPC in 2011, and president of MPLX in 2012.

## Seated, left to right

**C. Richard Wilson**

Owner, Plough Penny Associates, LLC. Prior to Plough Penny, Mr. Wilson was an executive officer of Buckeye Partners, L.P., a petroleum pipeline company that became a master limited partnership in 1986. He served in various capacities at Buckeye and its general partner, including as president, chief operating officer, director and vice chairman.  
*(Retired Dec. 31, 2017)*

**John P. Surma**

Retired chairman and CEO, United States Steel Corp. Prior to USS, Mr. Surma held various leadership positions at Marathon Oil Co., including senior vice president of Finance and Accounting, president of Speedway SuperAmerica LLC, and president of Marathon Ashland Petroleum LLC.

**Timothy T. Griffith**

Senior vice president and chief financial officer, MPC. Prior to MPC, Mr. Griffith was vice president and treasurer of Smurfit-Stone Container Corp., vice president and treasurer of Cooper-Standard Automotive and assistant treasurer of Lear Corp. He also held positions at Comerica Inc. and Citicorp Securities.

**Michael J. Hennigan**

President, MPLX GP LLC. Prior to joining MPLX GP LLC in 2017, Mr. Hennigan was president, crude, NGL and refined products of the general partner of Energy Transfer Partners L.P. Prior to that, he served as president and chief executive officer of Sunoco Logistics Partners L.P. He was responsible for all operations and business activities, including setting the direction, strategy and vision for the company.

**Gary R. Heminger**

Chairman and CEO, MPLX GP LLC and chairman and CEO, MPC. Mr. Heminger joined Marathon Oil Co. in 1975 and held various leadership positions including head of Marathon's downstream operations beginning in 2001. Mr. Heminger was named president and CEO of Marathon Petroleum Corp. in 2011 and chairman in 2016. He assumed his current slate of roles in 2017.

**Dan D. Sandman**

Adjunct professor, The Ohio State University Moritz College of Law. Mr. Sandman began his career at Marathon Oil Co. in 1973 and served in various positions as an attorney before being appointed general counsel and secretary in 1986. In 1993, he was named general counsel and secretary of USX Corp. and in 2002, he was named vice chair of the board and chief legal and administrative officer of United States Steel Corp., retiring in 2007.



## COMPANY OFFICERS



### Standing, left to right

**C. Michael Palmer**  
Senior Vice President

**Suzanne Gagle**  
Vice President and General Counsel

**Peter Gilgen**  
Vice President and Treasurer

**Gregory S. Floerke**  
Executive Vice President, Gathering and Processing

**Raymond L. Brooks**  
Senior Vice President

**C. Kristopher Hagedorn**  
Vice President and Controller

**John S. Swearingen**  
Executive Vice President, Logistics and Storage

**Timothy J. Aydt**  
Vice President, Operations

**Molly R. Benson**  
Vice President, Corporate Secretary and Chief Compliance Officer

**Thomas M. Kelley**  
Senior Vice President

### Seated, left to right

**Michael J. Hennigan**  
President

**Gary R. Heminger**  
Chairman and Chief Executive Officer

**Pamela K.M. Beall**  
Executive Vice President and Chief Financial Officer

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

<i>(In millions, except per-unit, throughput and average tariff data)</i>	<b>2017</b>	<b>2016</b>
Revenues and other income	\$ 3,867	\$ 3,029
Net income attributable to MPLX LP	794	233
Limited partners' interest in net income attributable to MPLX LP	411	1
Adjusted EBITDA attributable to MPLX LP <sup>(1)</sup>	2,004	1,419
Distributable cash flow (DCF) <sup>(1)</sup>	1,563	1,099
<b>Net income per limited partner unit:</b>		
Common units – basic	\$ 1.07	\$ 0
Common units – diluted	1.06	0
<b>Weighted average limited partner units outstanding:</b>		
Common units – basic	385	331
Common units – diluted	388	338
Cash and cash equivalents	\$ 5	\$ 234
Total assets	19,500	17,509
Total debt <sup>(2)</sup>	7,332	4,423
Redeemable preferred units	1,000	1,000
Total equity	9,973	11,110
Capital expenditures: <sup>(3)</sup>		
Maintenance	108	88
Growth	1,518	1,292
<b>Pipeline throughput (mbpd):</b>		
Crude oil pipelines	1,936	1,643
Product pipelines	1,085	990
Total pipelines	3,021	2,633
<b>Average tariff rates (\$ per bbl):</b>		
Crude oil pipelines	0.56	0.57
Product pipelines	0.74	0.68
Total pipelines	0.63	0.61
<b>Gathering and Processing throughputs:<sup>(4)</sup></b>		
Natural gas processed (mmcf/d)	6,460	5,761
C2+ NGLs fractionated (mbpd)	394	335
Total gathering throughputs (mmcf/d):	3,608	3,275

(1) Non-GAAP measure. See Reconciliation Data on Page 9.

(2) Total debt for 2017 includes \$386 million of outstanding intercompany borrowings classified in current liabilities as of Dec. 31, 2017.

(3) See Reconciliation Data on Page 9.

(4) Includes amounts related to unconsolidated equity method investments on a 100 percent basis.

## RECONCILIATION DATA

**Reconciliation of adjusted EBITDA attributable to MPLX LP, and DCF attributable to GP and LP unitholders from net income (loss) (unaudited)**

<i>(In millions)</i>	Year Ended Dec. 31	
	2017	2016
<b>Net income</b>	<b>\$ 836</b>	<b>\$ 434</b>
Depreciation and amortization	683	591
Provision (benefit) for income taxes	1	(12)
Amortization of deferred financing costs	53	46
Non-cash equity-based compensation	15	10
Impairment expense	–	130
Net interest and other financial costs	301	215
(Income) loss from equity method investments <sup>(1)</sup>	(78)	74
Distributions from unconsolidated subsidiaries	241	148
Distributions of cash received from equity method investments to MPC	(31)	–
Other adjustments to equity method investment distributions	21	2
Unrealized derivative losses <sup>(2)</sup>	6	36
Acquisitions costs	11	(1)
<b>Adjusted EBITDA</b>	<b>2,059</b>	<b>1,673</b>
Adjusted EBITDA attributable to noncontrolling interests	(8)	(3)
Adjusted EBITDA attributable to Predecessor <sup>(3)</sup>	(47)	(251)
<b>Adjusted EBITDA attributable to MPLX LP</b>	<b>2,004</b>	<b>1,419</b>
Deferred revenue impacts	33	16
Net interest and other financial costs	(301)	(215)
Maintenance capital expenditures	(103)	(84)
Equity method investment capital expenditures paid out	(13)	(3)
Other	6	(1)
Portion of DCF adjustments attributable to Predecessor <sup>(3)</sup>	2	8
<b>DCF attributable to MPLX LP</b>	<b>1,628</b>	<b>1,140</b>
Preferred unit distributions	(65)	(41)
<b>DCF attributable to GP and LP unitholders</b>	<b>\$ 1,563</b>	<b>\$ 1,099</b>

(1) Includes an impairment expense of \$89 million related to one of the partnership's equity method investments for the year ended Dec. 31, 2016.

(2) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.

(3) The adjusted EBITDA and DCF adjustments related to Predecessor are excluded from adjusted EBITDA attributable to MPLX LP and DCF prior to the acquisition dates.

**Reconciliation of adjusted EBITDA attributable to MPLX LP, and DCF attributable to GP and LP unitholders from net cash provided by operating activities (unaudited)**

<i>(In millions)</i>	2017	2016
<b>Net cash provided by operating activities</b>	<b>\$ 1,907</b>	<b>\$ 1,491</b>
Changes in working capital items	(147)	(76)
All other, net	(28)	(16)
Non-cash equity-based compensation	15	10
Net gain on disposal of assets	–	1
Current income taxes	2	5
Net interest and other financial costs	301	215
Asset retirement expenditures	2	6
Unrealized derivative losses <sup>(1)</sup>	6	36
Acquisition costs	11	(1)
Distributions of cash received from equity method investments to MPC	(31)	–
Other adjustments to equity method investment distributions	21	2
<b>Adjusted EBITDA</b>	<b>2,059</b>	<b>1,673</b>
Adjusted EBITDA attributable to noncontrolling interests	(8)	(3)
Adjusted EBITDA attributable to Predecessor <sup>(2)</sup>	(47)	(251)
<b>Adjusted EBITDA attributable to MPLX LP</b>	<b>2,004</b>	<b>1,419</b>
Deferred revenue impacts	33	16
Net interest and other financial costs	(301)	(215)
Maintenance capital expenditures	(103)	(84)
Equity method investment capital expenditures paid out	(13)	(3)
Other	6	(1)
Portion of DCF adjustments attributable to Predecessor <sup>(2)</sup>	2	8
<b>DCF attributable to MPLX LP</b>	<b>1,628</b>	<b>1,140</b>
Preferred unit distributions	(65)	(41)
<b>DCF attributable to GP and LP unitholders</b>	<b>\$ 1,563</b>	<b>\$ 1,099</b>

(1) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.

(2) The adjusted EBITDA and DCF adjustments related to Predecessor are excluded from adjusted EBITDA attributable to MPLX LP and DCF prior to the acquisition dates.

Reconciliation Data continued on next page.

## RECONCILIATION DATA

## Reconciliation of Capital Expenditures (unaudited)

*(In millions)***Capital Expenditures <sup>(1)</sup>**

Maintenance

Growth

**Total capital expenditures**

Less: Increase (decrease) in capital accruals

Asset retirement expenditures

**Additions to property, plant and equipment**Capital expenditures of unconsolidated subsidiaries <sup>(2)</sup>**Total gross capital expenditures**

Less: Joint venture partner contributions

**Total capital expenditures, net**

Less: Maintenance capital

**Total growth capital expenditures**

## Year Ended Dec. 31

2017

2016

\$ 103

\$ 84

1,381

1,213

**1,484****1,297**

71

2

**1,411**

384

**1,795**

169

**1,626**

108

**\$ 1,518**

(22)

6

**1,313**

131

**1,444**

64

**1,380**

88

**\$ 1,292**

(1) Includes capital expenditures of the Predecessor for all periods presented.

(2) Capital expenditures includes amounts related to unconsolidated, partnership operated subsidiaries.

Below: MPLX's  
Houston complex  
in Pennsylvania



**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

**Form 10-K**

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

For the Fiscal Year Ended December 31, 2017

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission file number 001-35714

**MPLX LP**

(Exact name of registrant as specified in its charter)

Delaware  
(State or other jurisdiction of  
incorporation or organization)

27-0005456  
(I.R.S. Employer  
Identification No.)

200 E. Hardin Street, Findlay, Ohio 45840

(Address of principal executive offices)

(419) 421-2414

(Registrant's telephone number, including area code)

**Securities registered pursuant to Section 12(b) of the Act:**

Title of each class

Name of each exchange on which registered

Common Units Representing Limited Partnership Interests

New York Stock Exchange

**Securities registered pursuant to Section 12(g) of the Act:** None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes  No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes  No

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer  Accelerated filer

Non-accelerated filer  Smaller reporting company

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.

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

The aggregate market value of common units held by non-affiliates as of June 30, 2017 was approximately \$9.4 billion. Common units held by executive officers and directors of the registrant and its affiliates are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers and those of its affiliates to be affiliates.

MPLX LP had 793,819,108 common units outstanding at February 16, 2018.

**DOCUMENTS INCORPORATED BY REFERENCE:**

None

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### MPLX LP

Unless the context otherwise requires, references in this report to “MPLX LP,” “the Partnership,” “we,” “our,” “us,” or like terms refer to MPLX LP and its subsidiaries, including MPLX Operations LLC (“MPLX Operations”), MPLX Terminal and Storage LLC (“MPLX Terminal and Storage”), MarkWest Energy Partners, L.P. (“MarkWest”), MarkWest Hydrocarbon, L.L.C. (“MarkWest Hydrocarbon”), MarkWest Pioneer, L.L.C. (“MarkWest Pioneer”), MPLX Pipe Line Holdings LLC (“Pipe Line Holdings”), Marathon Pipe Line LLC (“MPL”), Ohio River Pipe Line LLC (“ORPL”), Hardin Street Marine LLC (“HSM”), Hardin Street Transportation LLC (“HST”), Woodhaven Cavern LLC (“WHC”) and MPLX Terminals LLC (“MPLXT”). We have partial ownership interests in a number of joint venture legal entities, including MarkWest Utica EMG, L.L.C. (“MarkWest Utica EMG”) and its subsidiary Ohio Gathering Company, L.L.C. (“Ohio Gathering”), Ohio Condensate Company, L.L.C. (“Ohio Condensate”), Wirth Gathering Partnership (“Wirth”), MarkWest EMG Jefferson Dry Gas Gathering Company, L.L.C. (“Jefferson Dry Gas”), Sherwood Midstream LLC (“Sherwood Midstream”), Sherwood Midstream Holdings LLC (“Sherwood Midstream Holdings”), MarEn Bakken Company, LLC (“MarEn Bakken”), Johnston County Terminal, LLC (“Johnston Terminal”), Guilford County Terminal Company, LLC (“Guilford Terminal”), LOOP LLC (“LOOP”), LOCAP LLC (“LOCAP”), Illinois Extension Pipeline Company, L.L.C. (“Illinois Extension”) and Explorer Pipeline Company (“Explorer”). References to “MPC” refer collectively to Marathon Petroleum Corporation and its subsidiaries, other than the Partnership. Unless otherwise specified, references to “Predecessor” refer collectively to HSM’s, HST’s, WHC’s and MPLXT’s related assets, liabilities and results of operations effective January 1, 2014 for HSM, January 1, 2015 for HST and WHC and April 1, 2016 for MPLXT.

## Glossary of Terms

The abbreviations, acronyms and industry technology used in this report are defined as follows.

ATM Program	An at-the-market program for the issuance of common units
ARO	Asset retirement obligation
Bbl	Barrels
Bcf/d	One billion cubic feet of natural gas per day
Btu	One British thermal unit, an energy measurement
Class A Reorganization	On September 1, 2016, a series of reorganization transactions were initiated in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements, resulting in the elimination of all previously issued and outstanding MPLX LP Class A units
Condensate	A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions
DCF (a non-GAAP financial measure)	Distributable Cash Flow
DOT	United States Department of Transportation
Dth/d	Dekatherms per day
EBITDA (a non-GAAP financial measure)	Earnings Before Interest, Taxes, Depreciation and Amortization
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Gal	Gallon
Gal/d	Gallons per day
IDR	Incentive distribution right
Initial Offering	Initial public offering on October 31, 2012
IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
MarkWest Merger	On December 4, 2015, a wholly-owned subsidiary of the Partnership merged with MarkWest Energy Partners L.P.
mbbls	Thousands of barrels
mbpd	Thousand barrels per day
mcf	One thousand cubic feet of natural gas
MMBtu	One million British thermal units, an energy measurement
MMcf/d	One million cubic feet of natural gas per day
Net operating margin (a non-GAAP financial measure)	Segment revenues, less purchased product costs, less derivative gains (losses) related to purchased product costs
NGL	Natural gas liquids, such as ethane, propane, butanes and natural gasoline
NYSE	New York Stock Exchange
OTC	Over-the-Counter
PADD	Petroleum Administration for Defense District
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of MPLX LP, dated as of October 31, 2016, as amended
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPI	Producer Price Index
Predecessor	Collectively: <ul style="list-style-type: none"> <li>• HSM's related assets, liabilities, and results of operations prior to the date of the acquisition, March 31, 2016, effective January 1, 2015</li> <li>• HST's, WHC's and MPLXT's related assets, liabilities and results of operations prior to the date of the acquisition, March 1, 2017, effective January 1, 2015 for HST and WHC and April 1, 2016 for MPLXT</li> </ul>

Realized derivative gain/loss  
SEC  
SMR

The gain or loss recognized when a derivative matures or is settled  
United States Securities and Exchange Commission  
Steam methane reformer, operated by a third party and located at the  
Javelina gas processing and fractionation complex in Corpus Christi,  
Texas

Unrealized derivative gain/loss

The gain or loss recognized on a derivative due to changes in fair  
value prior to the instrument maturing or settling

USCG  
VIE  
WTI

United States Coast Guard  
Variable interest entity  
West Texas Intermediate



## Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements. You can identify our forward-looking statements by words such as “anticipate,” “believe,” “design,” “estimate,” “objective,” “expect,” “forecast,” “goal,” “guidance,” “imply,” “intend,” “opportunity,” “outlook,” “plan,” “position,” “potential,” “predict,” “project,” “prospective,” “pursue,” “seek,” “strategy,” “target,” “could,” “may,” “should,” “would,” “will” or other similar expressions that convey the uncertainty of future events or outcomes. In accordance with “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include, but are not limited to, statements that relate to, or statements that are subject to risks, contingencies or uncertainties that relate to:

- future levels of revenues and other income, income from operations, net income attributable to MPLX LP, earnings per unit, Adjusted EBITDA or DCF (please read Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information for the definitions of Adjusted EBITDA and DCF);
- anticipated levels of regional, national and worldwide prices of crude oil, natural gas, NGLs and refined products;
- anticipated levels of drilling activity, production rates and volumes of throughput of crude oil, natural gas, NGLs, refined products or other hydrocarbon-based products;
- future levels of capital, environmental or maintenance expenditures, general and administrative and other expenses;
- the success or timing of completion of ongoing or anticipated capital or maintenance projects;
- expectations regarding joint venture arrangements and other acquisitions, including the dropdowns completed by MPC, or divestitures of assets;
- business strategies, growth opportunities and expected investments;
- the effect of restructuring or reorganization of business components;
- the potential effects of judicial or other proceedings on our business, financial condition, results of operations and cash flows;
- the potential effects of changes in tariff rates on our business, financial condition, results of operations and cash flows;
- the adequacy of our capital resources and liquidity, including, but not limited to, availability of sufficient cash flow to pay distributions and execute our business plan;
- our ability to successfully implement our growth strategy, whether through organic growth or acquisitions;
- capital market conditions, including the cost of capital, and our ability to raise adequate capital to execute our business plan and implement our growth strategy; and
- the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local regulatory authorities, or plaintiffs in litigation.

We have based our forward-looking statements on our current expectations, estimates and projections about our industry and our partnership. We caution that these statements are not guarantees of future performance and you

should not rely unduly on them, as they involve risks, uncertainties and assumptions that we cannot predict. In addition, we have based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. While our management considers these assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, our actual results may differ materially from the future performance that we have expressed or forecast in our forward-looking statements. Differences between actual results and any future performance suggested in our forward-looking statements could result from a variety of factors, including the following:

- changes in general economic, market or business conditions;
- changes in the economic and financial condition of MPLX LP;
- risks and uncertainties associated with intangible assets, including any future goodwill or intangible assets impairment charges;
- changes in producer customers' drilling plans or in volumes of throughput of crude oil, natural gas, NGLs, refined products or other hydrocarbon-based products;
- changes in regional, national and worldwide prices of crude oil, natural gas, NGLs and refined products;
- domestic and foreign supplies of crude oil and other feedstocks, natural gas, NGLs and refined products such as gasoline, diesel fuel, jet fuel, home heating oil and petrochemicals;
- foreign imports and exports of crude oil, refined products, natural gas and NGLs;
- midstream and refining industry overcapacity or undercapacity;
- changes in the cost or availability of third-party vessels, pipelines, railcars and other means of transportation for crude oil, natural gas, NGLs, feedstocks and refined products;
- price, availability and acceptance of alternative fuels and alternative-fuel vehicles and laws mandating such fuels or vehicles;
- fluctuations in consumer demand for refined products, natural gas and NGLs, including seasonal fluctuations;
- changes in our capital budget, maintenance capital expenditure requirements or changes in costs of planned capital projects;
- political and economic conditions in nations that consume refined products, natural gas and NGLs, including the United States, and in crude oil producing regions, including the Middle East, Africa, Canada and South America;
- actions taken by our competitors and the expansion and retirement of pipeline, processing, fractionation and treating capacity in response to market conditions;
- changes in fuel and utility costs for our facilities;
- failure to realize the benefits projected for capital projects, or cost overruns associated with such projects;
- the ability to successfully implement growth strategies, whether through organic growth or acquisitions;
- accidents or other unscheduled shutdowns affecting our pipelines, processing, fractionation and treating facilities or equipment, or those of our suppliers or customers or facilities upstream or downstream of our facilities;
- unusual weather conditions and natural disasters;

- disruptions due to equipment interruption or failure;
- acts of war, terrorism or civil unrest that could impair our ability to gather, process, fractionate or transport crude oil, natural gas, NGLs or refined products;
- legislative or regulatory action, which may adversely affect our business or operations;
- rulings, judgments or settlements in litigation or other legal, tax or regulatory matters, including unexpected environmental remediation costs, in excess of any reserves or insurance coverage;
- political pressure and influence of environmental groups upon policies and decisions related to the production, gathering, processing, fractionation, refining, transportation and marketing of natural gas, oil, NGLs or other carbon-based fuels;
- labor and material shortages;
- the ability and willingness of parties with whom we have material relationships to perform their obligations to us;
- capital market conditions, including an increase of the current yield on MPLX LP common units, adversely affecting MPLX LP's ability to meet its distribution growth guidance;
- increases in and availability of equity capital, changes in the availability of unsecured credit, changes affecting the credit markets generally and our ability to manage such changes; and
- the other factors described in Item 1A. Risk Factors.

We undertake no obligation to update any forward-looking statements except to the extent required by applicable law.

## **Part I**

### **Item 1. Business**

#### **OVERVIEW**

We are a diversified, growth-oriented master limited partnership (“MLP”) formed in 2012 by MPC to own, operate, develop and acquire midstream energy infrastructure assets. We are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering, transportation and storage of crude oil and refined petroleum products.

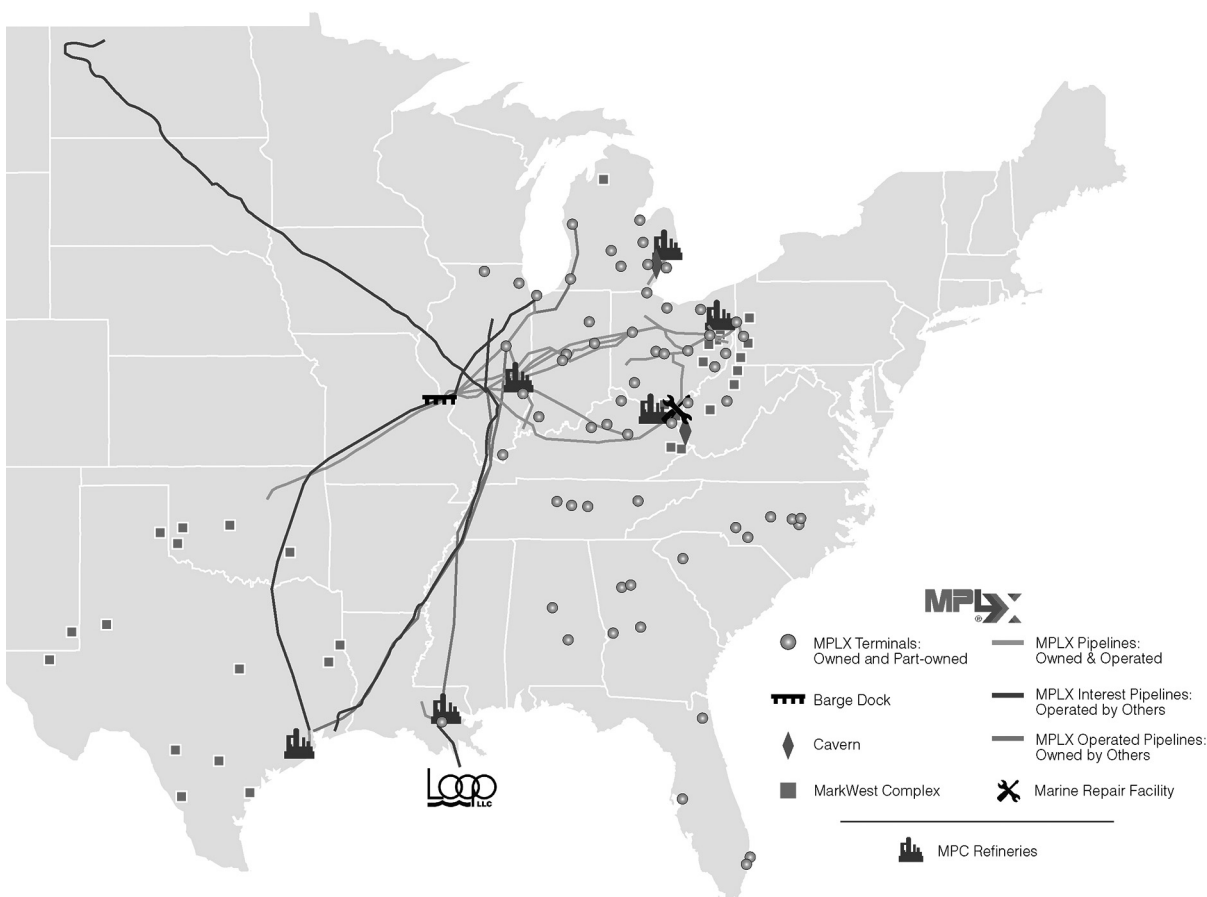
As of December 31, 2017, our assets included 1,613 miles and 2,360 miles of owned or leased and operated crude oil and product pipelines, respectively, and partial ownership in 2,194 miles and 1,917 miles of crude oil and products pipelines, respectively, all of which are across 17 states; a barge dock facility with approximately 78 mbpd of crude oil throughput capacity; crude oil and product storage facilities (tank farms) with approximately 18,642 mbbls of available storage capacity; nine butane and propane storage caverns with approximately 2,755 mbbls of NGL storage capacity; 59 light products terminal facilities, one leased terminal and partial ownership in two terminals, with a combined total shell capacity of approximately 23.8 million barrels; an inland marine business, comprised of 18 tow boats and 232 barges; and gathering and processing infrastructure, with approximately 5.9 bcf/d of gathering capacity, 8.0 bcf/d of natural gas processing capacity and approximately 610 mbpd of fractionation capacity, acquired as a result of the December 4, 2015 merger with MarkWest (the “MarkWest Merger”), one of the largest processors of natural gas in the United States and the largest processor and fractionator in the Marcellus and Utica shale plays.

MPC is our sponsor and a large source of our revenues. We have multiple transportation and storage services agreements with MPC. These agreements are long-term, fee-based agreements with minimum volume commitments and, therefore, MPC will continue to be an important source of our revenues for the foreseeable future. Further, as a result of the MarkWest Merger, we also have long-term relationships with a diverse set of producer customers in many natural gas resource plays, including the Marcellus Shale, Utica Shale, Huron/Berea Shale, Haynesville Shale, STACK Shale, Granite Wash formation and the Permian Basin.

MPC’s significant interest in us and its stated intent to grow its midstream business has been evidenced by the completion of three dropdown acquisitions of MLP-qualifying midstream assets throughout 2017 and early 2018 projected to generate \$1.4 billion of annual EBITDA, as discussed below. Immediately following the completion of the dropdowns, our general partner’s IDRs were eliminated and its two percent economic general partner interest in MPLX LP was converted into a non-economic general partner interest, all in exchange for 275 million newly issued MPLX LP common units (“GP IDR Exchange”), also described below. As of February 1, 2018, MPC controlled our general partner, MPLX GP LLC (“MPLX GP”), in addition to owning approximately 64 percent of our outstanding common units.

We have significant organic growth opportunities to expand midstream services throughout major shale plays in the United States. We may also pursue third-party midstream acquisitions independently or with MPC to complement our existing geographic footprint or expand our activities into new areas. We are backed by an investment grade credit profile, which provides strong financial flexibility in order to fund growth projects and execute our strategic plans.

We conduct our operations in the following operating segments: Logistics and Storage (“L&S”) and Gathering and Processing (“G&P”). For more information on these segments, see Our Operating Segments discussion below. The following map details our individual assets as of December 31, 2017:



The following table summarizes the operating performance for each segment for the year ended December 31, 2017. For further discussion of our segments and a reconciliation to our Consolidated Statements of Income, see Item 8. Financial Statements and Supplementary Data—Note 10.

	2017		
	L&S	G&P	Total
<i>(In millions)</i>			
<b>Revenues and other income:</b>			
Segment revenues	\$1,480	\$2,609	\$4,089
Segment other income	47	1	48
Total segment revenues and other income	1,527	2,610	4,137
<b>Costs and expenses:</b>			
Segment cost of revenues	692	1,105	1,797
Segment operating income before portion attributable to noncontrolling interests and Predecessor	835	1,505	2,340
Segment portion attributable to noncontrolling interests and Predecessor	53	170	223
<b>Segment operating income attributable to MPLX LP</b>	<b>\$ 782</b>	<b>\$1,335</b>	<b>\$2,117</b>

## RECENT DEVELOPMENTS

On February 1, 2018, the Partnership acquired MPLX Refining Logistics LLC (“Refining Logistics”) and MPLX Fuels Distribution LLC (“Fuels Distribution”) from MPC in exchange for cash and limited and general partnership units. Refining Logistics contains the integrated tank farm assets that support MPC’s refining operations. These essential logistics assets include: approximately 56 million barrels storage capacity (crude, finished products and intermediates), 619 tanks, 32 rail and truck racks, 18 docks, and gasoline blenders. Fuels Distribution is structured to provide a broad range of scheduling and marketing services as MPC’s sole and exclusive agent. The consideration for the transaction, which is projected to generate approximately \$1.0 billion of annual EBITDA, consisted of a cash payment of \$4.1 billion and a fixed number of common units and general partner units of 111.6 million and 2.3 million, respectively. The general partner units maintained MPC’s two percent economic general partner interest (“GP Interest”). Immediately following this transaction was the GP IDR Exchange. This exchange provides a clear valuation for MPC’s GP Interest in the Partnership, eliminates the general partner cash distribution requirements of the Partnership and is expected to be accretive to DCF attributable to common unitholders in the third quarter and for the full year 2018. MPC continues to own a non-economic general partner interest in the Partnership. See Item 8. Financial Statements and Supplementary Data—Note 24.

On January 26, 2018, we announced the board of directors of our general partner had declared a distribution of \$0.6075 per common unit that was paid on February 14, 2018 to common unitholders of record on February 5, 2018.

During 2017, we also executed on our organic growth plan, which included placing into service three new processing plants and three new fractionation plants in the Marcellus and Utica areas and increasing tank storage.

## ACQUISITIONS, INVESTMENTS AND OTHER HIGHLIGHTS

Effective January 1, 2017, the Partnership and Antero Midstream Partners LP (“Antero Midstream”) formed a joint venture, Sherwood Midstream LLC (“Sherwood Midstream”), to support Antero Resources Corporation’s (“Antero Resources”) development in the Marcellus Shale. The joint venture is also investing in fractionation capacity at MarkWest’s Hopedale Complex and has an option to invest in future fractionation expansions that support Antero Resources’ liquids production. See Item 8. Financial Statements and Supplementary Data—Note 5 for additional information.

On February 15, 2017, the Partnership closed on a joint venture with Enbridge Energy Partners L.P. in which MPLX LP acquired a partial, indirect interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Company Pipeline projects, collectively referred to as the Bakken Pipeline system, from Energy Transfer Partners, L.P. and Sunoco Logistics Partners, L.P. The Partnership holds, through a subsidiary, a 25 percent interest in the joint venture, which equates to a 9.1875 percent indirect interest in the Bakken Pipeline system. See Item 8. Financial Statements and Supplementary Data—Note 4 for additional information.

On March 1, 2017, the Partnership acquired the Ozark pipeline from Enbridge Pipelines (Ozark) LLC for approximately \$219 million. See Item 8. Financial Statements and Supplementary Data—Note 4 for additional information.

On March 1, 2017, the Partnership acquired HST, WHC and MPLXT from MPC for \$1.5 billion in cash and the issuance of \$503 million in MPLX LP equity. HST owns and operates various crude oil and refined product pipelines and associated storage tanks. WHC owns and operates butane and propane storage caverns and MPLXT owns and operates terminals for the receipt, storage, blending, additization, handling and redelivery of refined petroleum products. See Item 8. Financial Statements and Supplementary Data—Note 4 for additional information.

On July 1, 2017, each of the Partnership's remaining 3,990,878 Class B units automatically converted into 1.09 MPLX LP common units and the right to receive \$6.20 per unit in cash. MPC funded this cash payment, which reduced our liability payable to Class B unitholders by approximately \$25 million on July 1, 2017. As a result of the Class B units conversion, MPLX GP contributed less than \$1 million in exchange for 7,330 general partner units to maintain its two percent general partner interest. As common units outstanding as of the August 7, 2017 record date, the converted Class B units participated in the second quarter distribution. See Item 8. Financial Statements and Supplementary Data—Note 8 for additional information.

On September 1, 2017, the Partnership acquired joint-interest ownership in certain pipelines and storage facilities from MPC for \$420 million in cash and the issuance of \$653 million in MPLX LP equity. The acquired ownership interests include a 35 percent ownership interest in Illinois Extension, a 40.7 percent ownership interest in LOOP, a 58.52 percent ownership interest in LOCAP, and a 24.51 percent ownership interest in Explorer. See Item 8. Financial Statements and Supplementary Data—Note 4 for additional information.

During the year ended December 31, 2017, we issued an aggregate of 13,846,998 commons units under our ATM Program, generating net proceeds of approximately \$473 million.

## **BUSINESS STRATEGIES**

Our primary business objective is to enhance total unitholder returns through the generation of stable cash flows and growing distributions. We intend to accomplish this objective by executing the following strategies:

*Maintain and Strengthen Long-Term Integrated Relationships with Our Producer Customers.* We develop long-term integrated relationships with our producer customers. Our relationships are characterized by an intense focus on customer service and a deep understanding of our producer customers' requirements coupled with the ability to increase the level of our midstream services in response to their midstream requirements. Through collaborative planning, we construct midstream infrastructure and provide unique solutions that are critical to the ongoing success of our producer customers' development plans. As a result of delivering high-quality midstream services, MarkWest has been a top-rated midstream service provider since 2006 as determined by an independent research provider.

*Grow through Acquisitions.* In early 2018, we completed the final dropdown acquisition as part of the previously announced strategic plan to acquire assets from MPC projected to generate \$1.4 billion of annual EBITDA. As a result of these actions, as well as the Ozark pipeline acquisition and the acquisition of the joint venture interest in the Bakken Pipeline system, both of which occurred in the first quarter of 2017, we are one of the energy sector's largest diversified master limited partnerships and well-positioned to be a consolidator in the midstream sector. We intend to continue pursuing third-party midstream acquisitions independently or with MPC that complement our existing geographic footprint or expand our activities into new areas.

*Increase Operating Cash Flow and Pursue Organic Growth Opportunities.* We intend to increase operating cash flow by evaluating and capitalizing on organic investment opportunities that may arise in our areas of operations and increasing the utilization of our existing facilities by providing additional services for new and existing customers. We will evaluate organic growth projects both within our geographic footprint as well as in new areas that we consider strategic. With the support of MPC as our sponsor, we have the ability to develop incremental infrastructure to support growth across the hydrocarbon value chain.

*Focus on Fee-Based Businesses.* We are focused on generating stable cash flows through long-term contracts providing fee-based midstream services to MPC and third parties. For the full year ending December 31, 2018, we expect fee-based contracts to be approximately 95 percent of our net operating margin (for more information on net operating margin, which is a non-GAAP measure, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures).

*Sustain Long-Term Growth.* Our goal is to maintain an attractive distribution growth profile over the long term. Since the Initial Offering, we have increased our distribution for 20 consecutive quarters, which represents a compound annual growth rate of 18.3 percent over the minimum quarterly distribution. Our goal is to also optimize our cost of capital by maintaining an investment grade credit profile, providing visibility to growth and maintaining a strong distribution coverage, which will allow us to fund a higher proportion of our growth from internal cash flows. On February 1, 2018, we completed the GP IDR Exchange, which we believe creates one of the fastest and most pronounced paths to accretion compared with alternative general partner transactions. For the remainder of 2018, we expect to fund our organic growth needs from internal cash flows and debt, without the need to access public equity markets. See Item 8. Financial Statements and Supplementary Data—Note 24 for additional information. We believe our plans, along with the support of our sponsor, provide multiple avenues to support our distribution growth profile over the long-term.

*Maintain Safe and Reliable Operations.* We believe that providing safe, reliable and efficient services is a key component in generating stable cash flows, and we are committed to maintaining and improving the safety, reliability and efficiency of our operations. We intend to continue promoting a high standard for safety and environmental stewardship.

## **COMPETITIVE STRENGTHS**

We believe we are well-positioned to execute our business strategies based on the following competitive strengths:

*Extensive Portfolio of Strategically Located Assets.* Our L&S segment assets are primarily located in the Midwest and Gulf Coast regions of the United States and our G&P segment assets are primarily located in the Northeast and Southwest regions of the United States.

- Our L&S assets are strategically located and collectively support approximately 75 percent of total United States crude distillation capacity and can serve markets representing approximately 81 percent of total United States finished products demand for the year ended December 31, 2017, according to the EIA. These assets are located at the heart of the refining centers in the Midwest and Gulf Coast regions of the United States and are strategic to third-party business, as well as being integral to the success of MPC's operations, which include six refineries with an aggregate crude oil refining capacity of approximately 1.9 million barrels per calendar day.
- Our G&P segment is focused on regions of natural gas supply growth. We are one of the largest processors and fractionators in the United States.
  - We are the largest processor and fractionator in the Marcellus and Utica shale plays. As of December 31, 2017, our assets in the northeastern United States have combined processing capacity of approximately 6.7 bcf/d and combined fractionation capacity of approximately 578 mbpd, as well as an integrated NGL pipeline network and extensive logistics and marketing infrastructure. We believe our significant asset base and full-service midstream model provides us with strategic competitive advantages in capturing and contracting for gathering, processing and fractionating of new supplies of natural gas as production in the Northeast continues to increase.
  - We also have a growing presence in the southwestern portion of the United States with an existing strong competitive position; access to a significant reserve or customer base with a stable or growing production profile; ample opportunities for long-term continued organic growth; ready access to markets; and close proximity to other expansion opportunities. We have 1.4 bcf/d of processing capacity in the southwestern portion of the United States.

Additionally, we continually invest in the maintenance and integrity of our assets and have developed various programs to help us efficiently monitor and maintain them. For example, within the L&S segment, we utilize MPC's patented integrity management program that employs state-of-the-art mechanical integrity inspection and repair programs to enhance the safety of certain of our pipelines.



*Leading Midstream Positions Drive Investment Opportunities.* Our organic growth capital plan for 2018 is approximately \$2.2 billion, which does not include the first quarter 2018 dropdown previously discussed or its associated organic capital expenditures. The G&P segment capital plan includes investments that are expected to support producer customers and complete certain processing and fractionation plants. During 2018, we expect to complete 1.3 bcf/d of additional natural gas processing capacity and 100 mbpd of additional fractionation capacity, primarily in the Marcellus Shale and southwestern portion of the United States. The L&S segment capital plan includes the development of various crude oil and refined petroleum products infrastructure projects, a butane cavern and tank farm expansion and an expansion project to increase line capacity on the Ozark pipeline. We also have various organic growth prospects associated with the anticipated growth of MPC's operations and third-party activity in our areas of operation that we believe will provide attractive returns and cash flows. We also plan to pursue acquisitions of other midstream assets on a standalone basis or cooperatively with MPC.

*Strategic Relationship with MPC.* We have a strategic relationship with MPC and MPC views us as integral to its operations and is aligned with our success, as evidenced by its accelerated execution of the dropdown acquisitions. We believe MPC to be the largest crude oil refiner in the Midwest and the second-largest in the United States based on crude oil refining capacity. MPC is well-capitalized, with investment grade credit ratings. They own our general partner, an approximate 28.4 percent limited partner interest, and all of our incentive distribution rights as of December 31, 2017. As a result of this relationship, MPC serves as a stable revenue stream for MPLX LP and as we continue to provide services integral to the success of MPC, we believe that this relationship will continue to provide us with growth opportunities, as well as a base of stable cash flows.

*Stable and Predictable Cash Flows.* We generate a substantial majority of our revenue through long-term, fee-based agreements and have minimal direct commodity exposure. We believe our long-term contracts, which we define as contracts with remaining terms of four years or more, lend greater stability to our cash flow profile. Further, the dropdown acquisitions have substantially contributed stable fee-based earnings streams and have diversified the financial profile of the Partnership. The table below provides long-term contract details by segment as of December 31, 2017:

	<u>Remaining contract term</u>	<u>% of volumes</u>
L&S segment	5-9 years	77%
G&P segment	4 to 21 years	87%

We manage our business by taking into account the partial offset of short natural gas positions primarily in the Southwest region of our G&P segment. For the year ended December 31, 2017, we calculated the following approximate percentages of our net operating margin from the following types of contracts:

	<u>Fee-Based</u>	<u>Other<sup>(1)</sup></u>
L&S <sup>(2)</sup>	100%	—%
G&P <sup>(2)(3)</sup>	86%	14%
Total	92%	8%

(1) Includes percent-of-proceeds, keep-whole and other types of arrangements tied to NGL, condensate and natural gas prices.

(2) Detail on contract types provided below.

(3) Includes unconsolidated affiliates (See Item 8. Financial Statements and Supplementary Data—Note 5).

*Financial Flexibility.* As of December 31, 2017, we had \$5 million of cash and approximately \$1.9 billion available on our revolving credit facility and our loan agreement with MPC Investment LLC ("MPC Investment"), a wholly owned subsidiary of MPC. We are committed to maintaining our investment grade credit profile, and we anticipate that we will not issue public equity to fund organic growth in 2018. Further, the elimination of MPC's IDRs and conversion of its two percent general partner interest into a non-economic

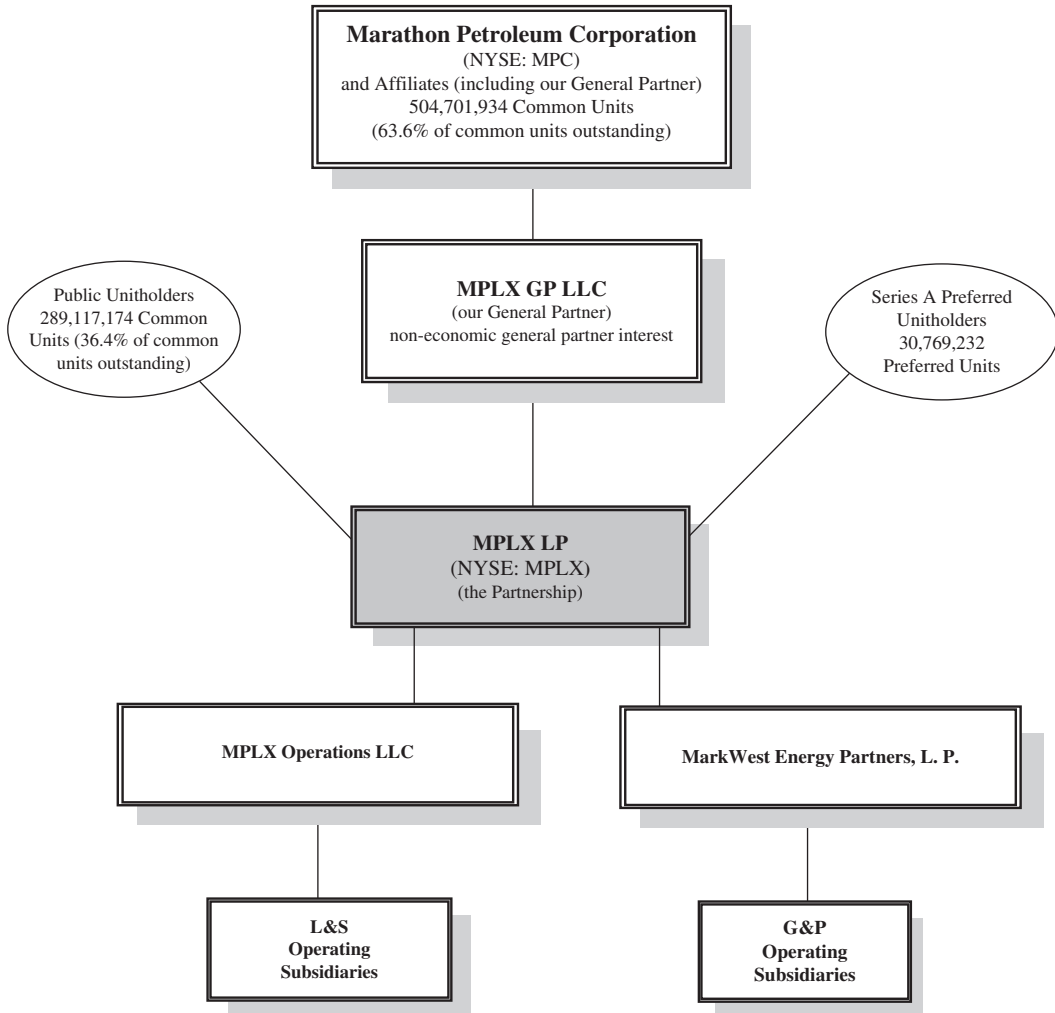
general partner interest in exchange for MPLX LP common units on February 1, 2018 eliminated the general partner cash distribution requirements of the Partnership and is expected to be accretive to DCF attributable to common unitholders in the third quarter and for the full year 2018. We believe that these actions allow us to have financial flexibility to execute our growth strategy through excess cash reserves, borrowing capacity under our revolving credit facilities as well as access to the debt and equity capital markets if so desired in the future. See Item 8. Financial Statements and Supplementary Data—Note 8 and Note 17 for additional information regarding our recent transactions related to debt and equity offerings.

*Experienced Management Team.* Our management team has substantial experience in the management and operation of midstream assets. Our management team also has expertise in acquiring and integrating assets as well as executing growth strategies in the midstream sector.

The above discussion contains forward-looking statements with respect to the business and operations of MPLX LP, including the anticipated effects of the dropdown acquisitions and GP IDR Exchange with MPC, our business strategies, competitive strengths and the Partnership's capital budget, all of which are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include negative capital market conditions, including an increase of the current yield on common units, adversely affecting the Partnership's ability to meet its distribution growth guidance; our ability to achieve the strategic and other objectives discussed herein and other proposed transactions; adverse changes in laws including with respect to tax and regulatory matters; the adequacy of the Partnership's capital resources and liquidity, including, but not limited to, availability of sufficient cash flow to pay distributions and access to debt on commercially reasonable terms, and the ability to successfully execute its business plans and growth strategy; the timing and extent of changes in commodity prices and demand for crude oil, refined products, feedstocks or other hydrocarbon-based products; continued/further volatility in and/or degradation of market and industry conditions; changes to the expected construction costs and timing of projects; completion of midstream infrastructure by competitors; disruptions due to equipment interruption or failure, including electrical shortages and power grid failures; the suspension, reduction or termination of MPC's obligations under the Partnership's commercial agreements; modifications to earnings and distribution growth objectives; our ability to manage disruptions in credit markets or changes to our credit rating; compliance with federal and state environmental, economic, health and safety, energy and other policies and regulations and/or enforcement actions initiated thereunder; adverse results in litigation; changes to the Partnership's capital budget; prices of and demand for natural gas, NGLs, crude oil and refined products, delays in obtaining necessary third-party approvals and governmental permits, changes in labor, material and equipment costs and availability, planned and unplanned outages, the delay of, cancellation of or failure to implement planned capital projects, project overruns, disruptions or interruptions of our operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations. These factors, among others, could cause actual results to differ materially from those set forth in the forward-looking statements. For additional information on forward-looking statements and risks that can affect our business, see "Disclosures Regarding Forward-Looking Statements" and Item 1A. Risk Factors in this Annual Report on Form 10-K.

**ORGANIZATIONAL STRUCTURE**

The following diagram depicts our organizational structure and MPC’s ownership interests in us as of February 16, 2018.



We are an MLP with outstanding common units and Preferred units.

- Our common units are publicly traded on the NYSE under the symbol “MPLX.”
- The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to \$0.528125 per unit commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will be entitled to receive as a distribution the greater of \$0.528125 per unit or the amount of per unit distributions paid to common units. The purchasers may convert their Preferred units into common units, at any time after the third anniversary of the issuance date or prior to liquidation, dissolution or winding up of the Partnership, in full or in part, subject to minimum conversion amounts and conditions. After the fourth anniversary of the issuance date, the Partnership may convert the Preferred units into common units at any time, in whole or in part, subject to certain minimum conversion amounts and conditions, if the closing price of MPLX LP common units is greater than \$48.75 for the 20 day trading period immediately preceding the conversion notice date.

The conversion rate for the Preferred units shall be the quotient of (a) the sum of (i) \$32.50, plus (ii) any unpaid cash distributions on the applicable Preferred unit, divided by (b) \$32.50 (as proportionately adjusted for any unit splits, unit distributions or similar transactions). The holders of the Preferred units are entitled to vote on an as-converted basis with the common unitholders and have certain other class voting rights with respect to any amendment to the Partnership Agreement that would adversely affect any rights, preferences or privileges of the Preferred units. In addition, upon certain events involving a change in control the holders of Preferred units may elect, among other potential elections, to convert their Preferred units to common units at the then applicable change of control conversion rate.

## INDUSTRY OVERVIEW

As of December 31, 2017, our diversified services in the midstream sector are across the hydrocarbon value chain. The types of midstream services provided by both our L&S and G&P segments are as follows:

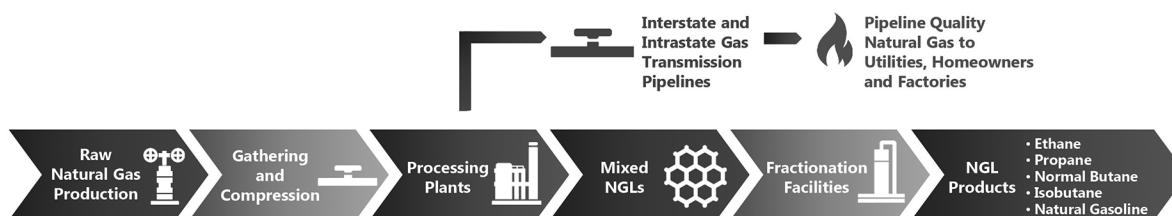
### L&S:

Our L&S assets are integral to the success of MPC's operations related to transportation and storage across the hydrocarbon value chain.

- Logistics.* Crude oil is the primary raw material for transportation fuels and the basis for many products including plastics and petrochemicals, in addition to heating oil for homes once it is refined and prepared for use. While many forms of transportation are used to move this product to storage hubs and refineries, we believe pipelines and marine vessels are among the safest, most efficient and cost-effective ways to move this resource to refineries and to market. Pipelines bring advantaged North American crude oil from the upper Great Plains, Louisiana, Texas and Canada to numerous refiners. Pipelines and marine vessels are also used to effectively move refined products from refineries to customers and end markets. Terminal facilities provide for the receipt, storage, blending, additization, handling and redelivery of refined petroleum products.
- Storage.* The hydrocarbon market is often volatile and the ability to take advantage of fast-moving market conditions is enhanced by our ability to store crude oil and other hydrocarbon-based products at our tank farms and butane and propane caverns. Storage facilities provide flexibility and logistics optionality, which enhances MPC's ability to maximize returns for refined products.

### G&P:

The midstream natural gas industry is the link between the exploration for, and production of, natural gas and the delivery of its hydrocarbon components to end-use markets. The components of this value chain are graphically depicted and further described below:



- Gathering.* The natural gas production process begins with the drilling of wells into gas-bearing rock formations. At the initial stages of the midstream value chain, a network of pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw, or untreated, natural gas to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells.

Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow gathering of additional production without significant incremental capital expenditures.

- *Compression.* Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to be gathered more efficiently and delivered into a higher pressure system, processing plant or pipeline. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. Since wells produce at progressively lower field pressures as they deplete, field compression is needed to maintain throughput across the gathering system.
- *Treating and dehydration.* To the extent that gathered natural gas contains contaminants, such as water vapor, carbon dioxide and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.
- *Processing.* Natural gas has a widely varying composition depending on the field, formation reservoir or facility from which it is produced. Processing removes the heavier and more valuable hydrocarbon components, which are extracted as a mixed NGL stream that includes ethane, propane, butanes and natural gasoline (also referred to as “y-grade”). Processing aids in allowing the residue gas remaining after extraction of NGLs to meet the quality specifications for long-haul pipeline transportation and commercial use.
- *Fractionation.* Fractionation is the separation of the mixture of extracted NGLs into individual components for end-use sale. It is accomplished by controlling the temperature and pressure of the stream of mixed NGLs in order to take advantage of the different boiling points and vapor pressures of separate products. Fractionation systems typically exist either as an integral part of a gas processing plant or as a central fractionator, often located many miles from the primary production and processing complex. A central fractionator may receive mixed streams of NGLs from many processing plants. A fractionator can fractionate one product or in a central fractionator, multiple products. We operate fractionation facilities at certain processing facilities that separate ethane from the remainder of the y-grade stream. We also operate central fractionation facilities that separate y-grade into propane, butanes and natural gasoline.
- *Storage, transportation and marketing.* Once the raw natural gas has been treated or processed and the raw NGL mix has been fractionated into individual NGL components, the natural gas is delivered to downstream transmission pipelines and NGL components are stored, transported and marketed to end-use markets. We market NGLs domestically as well as for export to international markets. NGLs are transported via pipeline, railcar, including unit trains, and truck. Each pipeline typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily operational or supply-demand shifts. We have caverns for propane storage in the northeastern United States.

Due to advances in well completion technology and horizontal drilling techniques, unconventional sources, such as shale and tight sand formations, have become the most significant source of current and expected future natural gas production. The industry as a whole is characterized by regional competition, based on the proximity of gathering systems and processing/fractionation plants to producing natural gas wells, or to facilities that produce natural gas as a byproduct of refining crude oil. Due to the shift in the source of natural gas production, midstream providers with a significant presence in the shale plays will likely have a competitive advantage. Well-positioned operations allow access to all major NGL markets and provide for the development of export solutions for producers. This proximity is enhanced by infrastructure build-out and pipeline projects.

Basic NGL products and their typical uses are discussed below. The following basic NGL products are sold in our G&P segment.

- *Ethane* is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.
- *Propane* is used for heating, engine and industrial fuels, agricultural burning and drying and as a petrochemical feedstock for the production of ethylene and propylene.
- *Normal butane* is mainly used for gasoline blending, as a fuel gas, either alone or in a mixture with propane, and as a feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber.
- *Isobutane* is primarily used by refiners to enhance the octane content of motor gasoline.
- *Natural gasoline* is principally used as a motor gasoline blend stock or petrochemical feedstock.

The other primary products also produced and sold in our G&P segment are discussed below.

- *Ethylene* is primarily used in the production of a wide range of plastics and other chemical products.
- *Propylene* is primarily used in manufacturing plastics, synthetic fibers and foams. It is also used in the manufacture of polypropylene, which has a variety of end-uses including packaging film, carpet and upholstery fibers and plastic parts for appliances, automobiles, housewares and medical products.

## **OUR OPERATING SEGMENTS**

We conduct our operations in the following operating segments: L&S and G&P. As of December 31, 2017, our assets and operations in each of these segments are described below.

### ***L&S:***

The L&S segment includes transportation and storage of crude oil, refined products and other hydrocarbon-based products, primarily in the Midwest and Gulf Coast regions of the United States. These assets consist of a network of wholly and jointly-owned common carrier crude oil and refined product pipelines and associated storage assets, refined product terminals, storage caverns, and an inland marine business. Our pipeline network includes approximately 8,084 miles of pipeline across 17 states. Our storage caverns consist of a butane cavern in Neal, West Virginia with approximately 1,000 mbbbls of liquefied petroleum gas storage capacity, and eight active butane and propane storage caverns in Woodhaven, Michigan with approximately 1,755 mbbbls of NGL storage capacity. Our terminal facilities for the receipt, storage, blending, additization, handling and redelivery of refined petroleum products are located primarily in the Midwest, Gulf Coast and Southeast regions of the United States, and have a combined total shell capacity of approximately 23,789 mbbbls. Our marine business owns and operates boats, barges, and third-party chartered equipment and includes a Marine Repair Facility (“MRF”), which is a full service marine shipyard located on the Ohio River adjacent to MPC’s Catlettsburg, Kentucky refinery. Additionally, we have ownership in various joint-interests, including LOOP LLC, the only U.S. deepwater oil port, located offshore of Louisiana, which offloads crude oil from marine vessels destined for onshore storage and pipeline transport. We have completed the Cornerstone pipeline project, expanded and reversed pipelines, and increased tank storage to create a critical solution for the industry to move condensate and NGLs out of the Marcellus and Utica regions into refining centers in the Midwest and connect to the pipelines to Canada. MPLX LP acquired the Ozark pipeline in 2017, which is undergoing an expansion project to increase the line’s capacity to approximately 360 mbpd, expected to be completed mid-2018. Our L&S assets are integral to the success of MPC’s operations.

We generate revenue in the L&S segment primarily by charging tariffs for transporting crude oil, refined products and other hydrocarbon-based products through our pipelines and at our barge dock and fees for storing crude oil and refined products at our storage facilities. Our marine business generates revenue under a fee-for-capacity contract with MPC. We are also the operator of additional crude oil and refined product pipelines owned by MPC and third parties for which we are paid operating fees. For the year ended

December 31, 2017, approximately 92 percent of L&S segment revenue and other income was generated from MPC. In this segment, we do not take ownership of the crude oil or products that we transport and store for our customers, and we do not engage in the trading of any commodities. However, we could be required to purchase or sell crude oil volumes in the open market to make up negative or positive imbalances.

As of December 31, 2017, our marine transportation operations included 18 owned towboats as well as 208 owned and 24 leased barges that transport refined products and crude oil on the Ohio, Mississippi and Illinois rivers and their tributaries and inter-coastal waterways.

## **G&P:**

### *Natural Gas Gathering*

We operate several natural gas gathering systems that have a combined 5,903 MMcf/d throughput capacity in five states. The scope of gathering services that we provide depends on the composition of the raw, or untreated, gas at our producer customers' wellheads. For dry gas, we gather and, if necessary, treat the gas and deliver it to downstream transmission systems. For wet gas that contains heavier and more valuable hydrocarbons, we gather the gas for processing at a processing complex. The capacities of these gathering systems are supported by long-term fee-based agreements with major producer customers.

### *Natural Gas Processing*

Our natural gas processing complexes remove the heavier and more valuable hydrocarbon components from natural gas. This allows the residue gas remaining after extraction of the NGLs to meet the quality specifications for long-haul transmission pipeline transportation or commercial use.

We currently operate five complexes in the Marcellus Shale, including: processing, gathering, and C2+ fractionation at the Houston Complex located in Washington County, Pennsylvania (the "Houston Complex"); processing and de-ethanization at the Majorsville Complex located in Marshall County, West Virginia (the "Majorsville Complex"); processing and de-ethanization at the Mobley Complex located in Wetzel County, West Virginia (the "Mobley Complex"); processing and de-ethanization at the Sherwood Complex located in Doddridge County, West Virginia (the "Sherwood Complex"); and processing, gathering, and C2+ fractionation at the Bluestone Complex located in Butler County, Pennsylvania (previously referred to as Keystone). Further, we operate one condensate stabilization facility with two mbpd of capacity near the Houston Complex.

MarkWest Utica EMG, our joint venture with an affiliate of the Energy & Minerals Group, operates two complexes in the Utica Shale, including: processing and de-ethanization at the Cadiz Complex in Harrison County, Ohio (the "Cadiz Complex") and processing at the Seneca Complex in Noble County, Ohio (the "Seneca Complex"). MarkWest Liberty Midstream & Resources, LLC operates a C3+ fractionation complex at the Hopedale Complex located in Harrison County, Ohio (the "Hopedale Complex"). The Hopedale Complex is jointly owned by MarkWest Utica EMG and MarkWest Liberty Midstream. Further, Sherwood Midstream LLC (our joint venture between MarkWest Liberty Midstream LLC and Antero Midstream LLC) has rights to fractionation revenue and the obligation to pay expenses related to 20 mbpd of capacity in the Hopedale 3 fractionator at the Hopedale Complex. Ohio Condensate, our joint venture with Summit, operates one condensate stabilization facility with 23 mbpd of capacity.

We operate four processing complexes in the Appalachia region, including: the Kenova Complex located in Wayne County, West Virginia (the "Kenova Complex"); the Boldman Complex located in Pike County, Kentucky (the "Boldman Complex"); the Cobb Complex located in Kanawha County, West Virginia (the "Cobb Complex"); and the Langley Complex located in Langley, Kentucky (the "Langley Complex"). Further, we operate a C3+ fractionation complex at the Siloam Complex in South Shore, Kentucky (the "Siloam Complex").

We also operate five complexes in the Southwest region, including: processing and gathering at the Carthage Complex located in Panola County, Texas (the "Carthage Complex"); processing and gathering at the Western Oklahoma Complex located in Custer and Beckham Counties, Oklahoma (the "Western Oklahoma Complex");

processing at the Hidalgo Complex located in Culberson County, Texas (the “Hidalgo Complex”); gathering at the Eagle Ford Complex located in Dimmit County, Texas (the “Eagle Ford Complex”); and treating, processing and C2+ fractionation at the Javelina Complex located in Corpus Christi, Texas (the “Javelina Complex”). We also own a 40 percent non-operating interest in the Centrahoma processing joint venture with Targa Resources. The joint venture includes processing plants in Southeast Oklahoma with existing capacity of 280 MMcf/d with plans to add two additional plants in 2018 with a combined capacity of 270 MMcf/d. The new plants are expected to be completed in the fourth quarter of 2018 and are not included in the following table.

The following table summarizes our current and planned processing assets:

Plant	Existing capacity (MMcf/d)	Expansion capacity under construction (MMcf/d)	Expected in- service of expansion capacity	Geographic Region
Bluestone Complex	410	—	N/A	Marcellus Operations
Harmon Creek Complex	—	200	Q4 2018	Marcellus Operations
Houston Complex <sup>(1)</sup>	520	200	Q1 2018	Marcellus Operations
Majorsville Complex <sup>(1)</sup>	1,070	200	Q3 2018	Marcellus Operations
Mobley Complex	920	—	N/A	Marcellus Operations
Sherwood Complex	1,800	400	Q3 2018 and Q4 2018	Marcellus Operations
Cadiz Complex <sup>(2)</sup>	525	—	N/A	Utica Operations
Seneca Complex <sup>(2)</sup>	800	—	N/A	Utica Operations
Kenova Complex	160	—	N/A	Southern Appalachian Operations
Boldman Complex	70	—	N/A	Southern Appalachian Operations
Cobb Complex	65	—	N/A	Southern Appalachian Operations
Langley Complex	325	—	N/A	Southern Appalachian Operations
Carthage Complex	600	—	N/A	Southwest Operations
Western Oklahoma Complex	425	75	Mid-2018	Southwest Operations
Hidalgo Complex	200	—	N/A	Southwest Operations
Argo Complex	—	200	Q1 2018	Southwest Operations
Javelina Complex	142	—	N/A	Southwest Operations
Total	<u>8,032</u>	<u>1,275</u>		

<sup>(1)</sup> We have the operational flexibility to process gas for producer customers at either complex.

<sup>(2)</sup> We have the operational flexibility to process gas for producer customers at either complex.

The following table summarizes our key producer customers and attributes for each geographic region:

	Marcellus Operations	Utica Operations	Southern Appalachian Operations	Southwest Operations
Key Producer Customers	Range Resources, Antero Resources <sup>(1)</sup> , EQT <sup>(1)</sup> , CNX, HG Energy <sup>(1)</sup> , Southwestern <sup>(1)</sup> , Rex and others	Antero Resources <sup>(1)</sup> , Gulfport, Ascent, Rice, and others	Core Appalachia <sup>(1)</sup> , EQT <sup>(1)</sup> and Transcanada <sup>(1)</sup>	Newfield, BP, Trinity, FourPoint Energy, CCI, Valero, and others
Volume Protection	76% of 2017 capacity contains minimum volume commitments	27% of 2017 capacity contains minimum volume commitments	24% of 2017 capacity contains minimum volume commitments	18% of 2017 capacity contains minimum volume commitments
Area Dedications	4.1 million acres	3.9 million acres	None	2.0 million acres

<sup>(1)</sup> We do not provide gathering services for these producer customers.



### *NGL Gathering*

Once natural gas has been processed at a natural gas processing complex, the heavier and more valuable hydrocarbon components, which have been extracted as a mixed NGL stream, can be further separated into their component parts through the process of fractionation.

### *C3+ NGL Fractionation Complexes*

Our NGL fractionation facilities separate the mixture of extracted NGLs into individual purity product components for end-use sale. All NGLs, other than purity ethane as discussed below, produced at our Majorsville Complex, Mobley Complex and Sherwood Complex are gathered to the Houston Complex or to the Hopedale Complex through a system of NGL pipelines to allow for fractionation into purity NGL products. We can also gather NGLs produced at a third party's processing facilities to the Houston, Hopedale and Bluestone Complexes for fractionation.

Our fractionation facilities for propane and heavier NGLs are supported by long-term, fee-based agreements with our key producer customers. The following tables summarize our current and planned fractionation assets at these facilities:

Facility	Existing propane and heavier NGLs + capacity (mbpd)	Propane and heavier NGLs expansion capacity under construction (mbpd)	Expected in-service of expansion capacity	Market outlets	Geographic Region
Bluestone Complex	47	—	N/A	Railcar and truck loading	Marcellus Operations
Hopedale Complex <sup>(1)</sup>	180	60	Q4 2018	Key interstate pipeline access Railcar and truck loading Marine vessels	Marcellus and Utica Operations
Houston Complex	60	—	N/A	Key interstate pipeline access Railcar and truck loading Marine vessels	Marcellus Operations
Siloam Complex	24	—	N/A	Railcar and truck loading Marine vessels	Southern Appalachian Operations
Javelina Complex	11	—	N/A	Key interstate pipeline access	Southwest Operations
Total	<u>322</u>	<u>60</u>			

<sup>(1)</sup> The Hopedale Complex is jointly owned by MarkWest Ohio Fractionation Company, L.L.C. (“Ohio Fractionation”) and MarkWest Utica EMG. Ohio Fractionation is a joint venture between MarkWest Liberty Midstream & Resources, L.L.C. (“MarkWest Liberty Midstream”) and Sherwood Midstream LLC (a joint venture between MarkWest Liberty and Antero Midstream LLC). MarkWest Liberty Midstream and Sherwood Midstream LLC are entities that operate in the Marcellus region, and MarkWest Utica EMG is an entity that operates in the Utica region. We account for MarkWest Utica EMG and Sherwood Midstream LLC as equity method investments. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

### *Ethane Recovery, Transportation and Associated Market Outlets*

As a result of the volume of natural gas production from the liquids-rich areas of the Marcellus and Utica Shales, we recover ethane from the natural gas stream for producer customers, which allows them to meet residue gas pipeline quality specifications and downstream pipeline commitments. Depending on market conditions, producer customers may also benefit from the potential price uplift received from the sale of their ethane. The following table summarizes our current and planned de-ethanization assets, which are, or are expected to be, supported by a network of purity ethane pipelines:

Facility	Existing ethane capacity (mbpd)	Ethane expansion capacity under construction (mbpd)	Expected in-service of expansion capacity	Geographic Region
Bluestone Complex	34	—	N/A	Marcellus Operations
Harmon Creek Complex	—	20	Q4 2018	Marcellus Operations
Houston Complex	40	—	N/A	Marcellus Operations
Majorsville Complex	80	—	N/A	Marcellus Operations
Mobley Complex	10	—	N/A	Marcellus Operations
Sherwood Complex	40	20	Q3 2018	Marcellus Operations
Cadiz Complex	40	—	N/A	Utica Operations
Javelina Complex	18	—	N/A	Southwest Operations
Total	<u>262</u>	<u>40</u>		

We have connections to several downstream ethane pipeline projects from many of our systems as follows:

- We transport purity ethane produced at the Majorsville Complex, Mobley Complex and the Sherwood Complex to the Houston Complex on a FERC pipeline.
- We deliver purity ethane to Sunoco Logistics Partners L.P.'s ("Sunoco") Mariner West pipeline ("Mariner West") from the Houston Complex and from the Bluestone Complex.
- We deliver purity ethane to Enterprise Products Partners L.P.'s Appalachia-to-Texas Express pipeline from the Houston Complex and the Cadiz Complex.
- Sunoco developed the Mariner East project ("Mariner East"), a pipeline and marine project that originates at our Houston Complex. In December 2014, Mariner East began transporting propane to Sunoco's terminal near Philadelphia, Pennsylvania ("Marcus Hook Facility") where it is loaded onto marine vessels and delivered to international markets. In May 2016, Mariner East began transporting purity ethane in addition to propane to the Marcus Hook Facility.
- Sunoco announced phase two of Mariner East ("Mariner East II") with plans to construct a pipeline from our Houston and Hopedale Complexes in western Pennsylvania and eastern Ohio, respectively, to transport propane and butane to the Marcus Hook Facility where it will be loaded onto marine vessels and delivered to domestic and international markets. The Mariner East II pipeline is expected to be operational in 2018.

A significant portion of our business comes from a limited number of key customers. For the year ended December 31, 2017, revenues earned from two customers are significant to the segment, accounting for 16 percent and 12 percent of G&P segment revenue and 9 percent of consolidated operating revenue, respectively.

For further financial information regarding our segments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included in this Annual Report on Form 10-K.

## OUR TRANSPORTATION, TERMINAL, AND STORAGE SERVICES AGREEMENTS WITH MPC

Our L&S assets are strategically located within, and integral to, MPC's operations. We have entered into multiple transportation, terminal, and storage services agreements with MPC. Under these long-term, fee-based agreements, we provide transportation, terminal, and storage services to MPC and, other than under our marine transportation service agreement, MPC has committed to provide us with minimum quarterly throughput and storage volumes. MPC has also committed to provide a fixed fee for 100 percent of available capacity for boats, barges and third-party chartered equipment under the marine transportation service agreement. All of our transportation services agreements for our crude oil and refined products pipelines include a 5 to 15 year term with various automatic renewal terms ranging from multiple two to five year terms, unless terminated by either party. Our butane and propane cavern storage services agreements include 10 to 17 year terms. Our terminal services agreement includes a ten-year term and automatically renews for one additional five-year term, unless terminated by either party. Our storage services agreements for our tank farms include a three-year term and automatically renew for additional one-year terms, unless terminated by either party. Our marine transportation service agreement includes an initial six-year term and automatically renews for up to two additional five-year terms, unless terminated by either party.

The following table sets forth additional information regarding our transportation, terminal, and storage services agreements with MPC:

<u>Agreement</u>	<u>Initiation Date</u>	<u>Term (years)</u>	<u>MPC minimum commitment<sup>(1)</sup></u>
<b>Transportation Services (mbpd):</b>			
Crude pipelines	Various	5-10	1,256
Product pipelines	Various	10-15	973
Marine	January 1, 2015	6	N/A <sup>(2)</sup>
<b>Storage Services (mbbls):</b>			
Caverns	Various	10-17	2,755
Tank Farms <sup>(3)</sup>	Various	3	18,642
Terminal Services (mbbls)	April 1, 2016	10	131,530

- (1) Quarterly commitments for our transportation services agreements refer to throughput in thousands of barrels per day. Commitments for our cavern storage services agreements refer to thousands of barrels. Commitments for our terminal services agreements refer to quarterly terminal throughput in thousands of barrels. Volumes shown for crude oil transportation services agreements are adjusted for crude viscosities. Minimum commitments on some agreements are reduced by any third-party throughput volumes.
- (2) MPC has committed to utilize 100 percent of our available capacity of tanks and barges.
- (3) Volume shown represents total tank farm capacity in thousands of barrels.

Under all of our transportation services agreements, except for our marine agreement, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay us a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect (the "Quarterly Deficiency Payment"). Under these transportation services agreements, the amount of any Quarterly Deficiency Payment paid by MPC may be applied as a credit for any volumes transported on the applicable pipeline in excess of MPC's minimum volume commitment during any of the succeeding four or eight quarters, after which time any unused credits will expire. Upon the expiration or termination of a transportation services agreement, MPC will have the opportunity to apply any such remaining credit amounts until the completion of any such four-quarter or eight-quarter period, as applicable. Any such remaining credits may be used against any volumes shipped by MPC on the applicable pipelines, without regard to any minimum volume commitment that may have been in place during the term of the agreement.

Under our terminal services agreement, if MPC fails to meet its minimum volume commitment during any quarter, then MPC will pay us a deficiency payment equal to the volume of the deficiency multiplied by the contractual fee then in effect.

MPC's obligations under these transportation and storage services agreements will not terminate if MPC no longer controls our general partner.

## **OPERATING AND MANAGEMENT SERVICES AGREEMENTS WITH MPC AND THIRD PARTIES**

### **Operating Agreements**

Through MPL, we operate various pipelines owned by MPC and third parties under existing operating services agreements that MPL has entered into with MPC and third parties. Under these operating services agreements, MPL receives an operating fee for operating the assets, which include certain MPC wholly-owned or partially-owned crude oil and refined product pipelines, and for providing various operational services with respect to those assets. MPL is generally reimbursed for all direct and indirect costs associated with operating the assets and providing such operational services. These agreements generally range from one to five years in length and automatically renew. Most of the agreements are indexed for inflation.

As noted above, MPL receives an annual fee for operating certain pipelines owned by MPC. MPC has agreed to indemnify MPL against any and all damages arising out of the operation of MPC's pipelines unless such occurrence is due to the gross negligence or willful misconduct of MPL. MPL has agreed to indemnify MPC against any and all damages arising out of MPL's gross negligence or willful misconduct in the operation of the pipelines. The initial term of this agreement was for one year and automatically renews from year-to-year unless terminated by either party.

Our existing operating services agreements include an operating agreement with Red Butte Pipe Line LLC, which is owned by a third party. Under this agreement, MPL receives an operating fee for operating certain pipelines in Wyoming and Montana. The term of this agreement is through December 2018. We also have operating services agreements with MPC under which MPL receives annual fees to provide services related to certain of MPC's refining assets.

MPL maintains and operates four joint interest pipelines including Capline, Centennial, Lou-Lex and Muskegon. MPL receives an operating fee for each of these pipelines, which is subject to adjustment for inflation. In addition, we are reimbursed for specific costs associated with operating each pipeline. The length and renewals terms for each agreement vary.

### **Management Services Agreement**

The Partnership, through its wholly-owned subsidiary, HSM, has a management services agreement with MPC under which it provides management services to assist MPC in the oversight and management of the marine business. HSM receives a fixed annual fee for providing the required management services. This fee is adjusted annually on the anniversary of the contract for inflation and any changes in the scope of the management services provided. This agreement is set to expire on January 1, 2021 and automatically renews for two additional renewal terms of five years each unless terminated by either party.

## **OTHER AGREEMENTS WITH MPC**

We have the following additional agreements with MPC:

- *Omnibus Agreement.* We have an omnibus agreement with MPC that addresses our payment of a fixed annual fee to MPC for the provision of executive management services by certain executive officers of our general partner and our reimbursement to MPC for the provision of certain general and administrative services to us, as well as MPC's indemnification of us for certain matters, including certain environmental, title and tax matters. In addition, we will indemnify MPC for certain matters under this agreement.

- *Employee Services Agreements.* We have various separate employee services agreements under which we reimburse MPC for the provision of certain operational and management services to us. All of the employees that conduct our business are employed by affiliates of our general partner.

## OUR RELATIONSHIP WITH MPC

One of our competitive strengths is our strategic relationship with MPC, which we believe to be the largest crude oil refiner in the Midwest and the second-largest in the United States, based on crude oil refining capacity. MPC owns and operates six refineries and associated midstream transportation and logistics assets in PADD II and PADD III, which consist of states in the Midwest and Gulf Coast regions of the United States, along with an extensive wholesale and retail refined product marketing operation that serves markets primarily in the Midwest, Gulf Coast and Southeast regions of the United States. MPC markets refined products under the Marathon brand through an extensive network of retail locations owned by independent entrepreneurs, and under the Speedway brand through its wholly-owned subsidiary, Speedway LLC, which operates what we believe to be the nation's second largest chain of company-owned and operated retail gasoline and convenience stores. In addition, MPC sells refined products in the wholesale markets. MPC had consolidated revenues of approximately \$75 billion in 2017. Marathon Petroleum Corporation's common stock trades on the NYSE under the symbol "MPC."

MPC retains a significant interest in us through its ownership of our general partner, an approximate 28.4 percent limited partner interest, and all of our incentive distribution rights as of December 31, 2017. We believe MPC will promote and support the successful execution of our business strategies given its significant interest in us and its stated intention to grow its midstream business. This was demonstrated by the 2017 and early 2018 dropdowns of MLP-qualifying assets and services projected to generate approximately \$1.4 billion in total of annual EBITDA. These transactions have and are expected to support increased limited partner distributions and provide value creation for investors.

## OUR G&P CONTRACTS WITH THIRD PARTIES

We generate the majority of our revenues in the G&P segment from natural gas gathering, transportation and processing; NGL gathering, transportation, fractionation, exchange, marketing and storage; and crude oil gathering and transportation. We enter into a variety of contract types. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described below. We provide services under the following types of arrangements:

- *Fee-based arrangements*—Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, processing and transmission of natural gas; gathering, transportation, fractionation and storage of NGLs; and gathering, transportation and storage of crude oil. The revenue we earn from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through our systems and facilities and is not normally directly dependent on commodity prices. In certain cases, our arrangements provide for minimum annual payments or fixed demand charges. Fee-based arrangements are reported as *Service revenue* on the Consolidated Statements of Income. In certain instances when specifically stated in the contract terms, we purchase product after fee-based services have been provided. Costs to purchase such products are reported as *Purchased product costs* and revenue from the sale of such products is reported as *Product sales* and recognized on a gross basis as we are the principal in the transaction.
- *Percent-of-proceeds arrangements*—Under percent-of-proceeds arrangements, we gather and process natural gas on behalf of producers, sell the resulting residue gas, condensate and NGLs at market prices and remit to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of the residue gas and NGLs to the producer (take-in-kind arrangements) and sell the volumes we retain to third parties. Revenue from these arrangements is reported on a gross basis where we act as the principal, as we have physical inventory risk and do not earn a fixed dollar amount. The agreed-upon percentage paid to the producer is reported as

*Purchased product costs* on the Consolidated Statements of Income. Revenue is recognized on a net basis when we act as an agent and earn a fixed dollar amount of physical product and do not have risk of loss of the gross amount of gas and/or NGLs. Percent-of-proceeds revenue is reported as *Product sales* on the Consolidated Statements of Income.

- *Keep-whole arrangements*—Under keep-whole arrangements, we gather natural gas from the producer, process the natural gas and sell the resulting condensate and NGLs to third parties at market prices. Because the extraction of the condensate and NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require us to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the NGL to gas ratio. Sales of NGLs under these arrangements are reported as *Product sales* on the Consolidated Statements of Income and are reported on a gross basis as we are the principal in the arrangement. Natural gas purchased to return to the producer and shared NGL profits are recorded as *Purchased product costs* in the Consolidated Statements of Income.
- *Purchase arrangements*—Under purchase arrangements, we purchase natural gas and/or NGLs at either (1) a percentage discount to a specified index price; (2) a specified index price less a fixed amount; or (3) a percentage discount to a specified index price less an additional fixed amount. We may purchase product at the inlet or outlet of our facility. We then resell the natural gas or NGLs at the index price or at a different percentage discount to the index price. Revenue generated from purchase arrangements are reported as *Product sales* on the Consolidated Statements of Income and are recognized on a gross basis as we purchase and take title to the product prior to sale and are the principal in the transaction.

In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. When fees are charged (in addition to product received) under keep-whole arrangements, percent-of-proceeds arrangements or percent-of-index arrangements, we record such fees as *Service revenue* on the Consolidated Statements of Income. When commodities are obtained as a result of providing our services, *Product sales* is recorded at the time the commodity is sold. The terms of our contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements.

Amounts billed to customers for shipping and handling, including fuel costs, are included in *Product sales* on the Consolidated Statements of Income, except under contracts where we are acting as an agent. Shipping and handling costs associated with product sales are included in *Purchased product costs* on the Consolidated Statements of Income. Taxes collected from customers and remitted to the appropriate taxing authority are excluded from revenue. Cost of revenues and depreciation represent those expenses related to operating our various facilities and are necessary to provide both *Product sales* and *Service revenue*. Reimbursements for third-party charges, such as electricity, are recorded net in *Cost of revenues*.

The terms of our contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. Our contract mix and, accordingly, our exposure to natural gas and NGL prices may change as a result of changes in producer preferences, our expansion in regions where some types of contracts are more common and other market factors, including current market and financial conditions which have increased the risk of volatility in oil, natural gas and NGL prices. Any change in mix may influence our long-term financial results.

## **COMPETITION**

Within our L&S segment, as a result of our contractual relationship with MPC under our transportation and storage services agreements, our terminal services agreement, and our physical asset connections to MPC's refineries and terminals, we believe that MPC will continue to utilize our assets for transportation or storage services.

If MPC's customers reduced their purchases of products from MPC due to the increased availability of less expensive products from other suppliers or for other reasons, MPC may ship only the minimum volumes (or pay the shortfall payment if it does not ship the minimum volumes), which would cause a decrease in our revenues. MPC competes with integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems, as well as with independent refiners, many of which also have their own distribution and marketing systems. MPC also competes with other suppliers that purchase refined products for resale. Competition in any particular geographic area is affected significantly by the volume of products produced by refineries in that area and by the availability of products and the cost of transportation to that area from distant refineries.

In our G&P segment, we face competition for natural gas gathering and in obtaining natural gas supplies for our processing and related services; in obtaining unprocessed NGLs for gathering and fractionation; and in marketing our products and services. Competition for natural gas supplies is based primarily on the location of gas gathering systems and gas processing plants, operating efficiency and reliability and the ability to obtain a satisfactory price for products recovered. Competitive factors affecting our fractionation services include availability of capacity, proximity to supply and industry marketing centers and cost efficiency and reliability of service. Competition for customers to purchase our natural gas and NGLs is based primarily on price, delivery capabilities, flexibility and maintenance of high-quality customer relationships.

Our competitors include:

- natural gas midstream providers, of varying financial resources and experience, that gather, transport, process, fractionate, store and market natural gas and NGLs;
- major integrated oil companies and refineries;
- medium and large sized independent exploration and production companies;
- major interstate and intrastate pipelines; and
- other marine and land-based transporters of natural gas and NGLs.

Some of our competitors operate as MLPs and may enjoy a cost of capital comparable to and, in some cases, lower than ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and contracted supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

We believe that our customer focus, demonstrated by our ability to offer an integrated package of services and our flexibility in considering various types of contractual arrangements, allows us to compete more effectively. Additionally, we believe we have critical connections to a strong sponsor and the key market outlets for NGLs and natural gas. In the Marcellus and Utica regions, our early entrance in the liquids-rich corridors of the Marcellus and Utica shale plays through our strategic gathering and processing agreements with key producers enhances our competitive position to participate in the further development of these resource plays. In the Southern Appalachia region, our operational experience of more than 20 years as the largest processor and fractionator and our existing presence in the Appalachian Basin provide a significant competitive advantage. In the Southwest region, our major gathering systems are less than 20 years old, located primarily in the heart of shale plays with significant long-term growth opportunities and provide producers with low-pressure and fuel-efficient service, which differentiates us from many competing gathering systems in those areas. The strategic location of our assets, including those connected to MPC, and the long-term nature of many of our contracts also provide a significant competitive advantage.

## **INSURANCE**

Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or

environmental damage and business interruption. We are insured under MPC and other third-party insurance policies. The MPC policies are subject to shared deductibles.

## **SEASONALITY**

The volume of crude oil and refined products transported and stored utilizing our assets is directly affected by the level of supply and demand for crude oil and refined products in the markets served directly or indirectly by our assets. Many effects of seasonality on the L&S segment's revenues will be mitigated through the use of our fee-based transportation and storage services agreements with MPC that include minimum volume commitments.

Our G&P segment can be affected by seasonal fluctuations in the demand for natural gas and NGLs and the related fluctuations in commodity prices caused by various factors such as changes in transportation and travel patterns and variations in weather patterns from year to year. However, we manage the seasonality impact through the execution of our marketing strategy. We have access to up to 50 million gallons of propane storage capacity in the Southern Appalachia region provided by an arrangement with a third party which provides us with flexibility to manage the seasonality impact. Overall, our exposure to the seasonal fluctuations in the commodity markets is declining due to our growth in fee-based business.

## **REGULATORY MATTERS**

Our operations are subject to extensive regulations. The failure to comply with applicable laws and regulations or to obtain, maintain and comply with requisite permits and authorizations can result in substantial penalties and other costs to the Partnership. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, reliance on the following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting our operations.

*Pipeline Control Operations.* The majority of our pipelines are operated from central control rooms. These control centers operate with a SCADA (supervisory control and data acquisition) system equipped with computer systems designed to continuously monitor operational data. Monitored data includes pressures, temperatures, gravities, flow rates and alarm conditions. These systems include real-time transient leak detection system monitors throughout and alarms if pre-established operating parameters are exceeded. These control centers operate remote pumps, motors and valves associated with the receipt and delivery of products, and provide for the remote-controlled shutdown of pump stations on the pipelines. These systems also include fully functional back-up operations maintained and routinely operated throughout the year to ensure safe and reliable operations.

*Common Carrier Liquids Pipeline Operations.* Our liquids pipelines are common carriers subject to regulation by various federal, state and local agencies. FERC regulates interstate transportation on liquids pipelines under the Interstate Commerce Act ("ICA"), Energy Policy Act of 1992 ("EPAct 1992") and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on these pipelines, including interstate pipelines that transport crude oil, natural gas liquids (including purity ethane) and refined petroleum products (collectively referred to as "petroleum pipelines"), be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. The ICA requires that interstate petroleum pipeline transportation rates and terms and conditions of service be filed with the governing agency, which is FERC, and FERC's regulations require the rate and rules and regulations tariffs to be publicly posted on the company's website. Under the ICA, persons with a substantial economic interest in a petroleum pipeline's rate or service may challenge that rate or service before FERC. FERC is authorized to investigate such charges and may suspend the effectiveness of a newly filed rate or service for up to seven months. A successful protest to a new rate or service could result in a petroleum pipeline paying refunds, together with interest, for the period that the rate or service was in effect. A successful protest could also result in FERC disallowing the rate or service. A successful complaint to an existing rate or service could result in a petroleum



pipeline paying reparations, together with interest, for the period beginning two years prior to the date of the complaint until the just and reasonable rate or service was established. FERC may also investigate, upon complaint, protest, or on its own motion, newly proposed rates and terms of service, existing rates and related rules, and may order a pipeline to change them prospectively or may bar a pipeline from implementing the proposed new or changed rates or terms of service.

EPA 1992 deemed certain interstate petroleum pipeline rates then in effect to be just and reasonable under the ICA. These rates are commonly referred to as “grandfathered rates.” Our rates in effect for the 365 day period ending on the date of the passage of EPA 1992 for interstate transportation service were deemed just and reasonable and therefore are grandfathered. New rates have since been established after EPA 1992 for certain pipelines, and the rates for certain of our products pipelines have subsequently been approved as market-based rates. FERC may order a change to the portion of a rate that is subject to grandfathering protection upon complaint only after it is shown that a substantial change has occurred since enactment in either the economic circumstances or the nature of the services that were a basis for the rate. EPA 1992 required FERC to establish a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines. As a result, FERC adopted an indexed rate methodology which, as currently in effect, allows petroleum pipelines to change their rates within prescribed ceiling levels that are tied to annual changes in the PPI. FERC’s indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, petroleum pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus an adder that is currently set at 1.23 percent and is reviewed every five years. The current adder will be in effect until June 30, 2021 or upon a formal rulemaking by FERC. The indexing methodology is applicable to existing rates, including grandfathered rates, with the exclusion of market-based rates and settlement rates (unless permitted under the settlement). A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so and rate increases made under the index are presumed to be just and reasonable unless a protesting party can demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline’s costs. However, FERC is currently evaluating when and how indexed adjustments to rates can be challenged as well as how pipelines must demonstrate their annual costs and incomes. Therefore, we cannot guarantee FERC will not make changes to its current policy regarding challenges in the future. Under the indexing rate methodology, in any year in which the index is negative, a pipeline must file to lower their rates if those rates would otherwise be above the rate ceiling, unless the pipeline makes a filing attesting that all shippers that pay the rate have approved the pipeline not lowering the rate.

While petroleum pipelines often use the indexing methodology to change their rates, petroleum pipelines may elect to support proposed rates by using other methodologies such as cost-of-service ratemaking, market-based rates and settlement rates. A pipeline can follow a cost-of-service approach when seeking to increase its rates above the rate ceiling provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can charge market-based rates if it establishes that it lacks significant market power in the affected markets. In addition, a pipeline can establish rates under settlement if agreed upon by all current shippers. We have used index rates, settlement rates and market-based rates to change the rates for our different FERC regulated petroleum pipelines.

FERC issued a policy statement in May 2005 stating that it would permit interstate petroleum pipelines, among others, to include an income tax allowance in cost-of-service rates to reflect actual or potential tax liability attributable to a regulated entity’s operating income, regardless of the form of ownership. Under FERC’s policy, a tax pass-through entity seeking such an income tax allowance must establish that its partners or members have an actual or potential income tax liability on the regulated entity’s income. Whether a pipeline’s owners have such actual or potential income tax liability is subject to review by FERC on a case-by-case basis. Although this policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. FERC’s income tax policy continues to be the subject of various appeals by shippers, before FERC and the courts, and recently the United States Court of Appeals for the District of

Columbia Circuit issued a ruling that remanded a case related to pass-through entities and the income tax allowance back to FERC for further review and consideration. FERC is currently reviewing pleadings that the parties to that case filed in response to the remand. We cannot guarantee that FERC, through an order related to that remand or through another order, or the courts will not make changes to the policy in the future.

Intrastate services provided by certain of our liquids pipelines are subject to regulation by state regulatory authorities. Much of the state regulation is complaint-based, both as to rates and priority of access. The state regulators could limit our ability to increase our rates or to set rates based on our costs or could order us to reduce our rates and could require the payment of refunds to shippers.

FERC and state regulatory agencies generally have not investigated rates on their own initiative when those rates are not the subject of a protest or a complaint by a shipper. MPC has agreed not to contest our tariff rates for the term of our transportation and storage services agreements with MPC, but we do not have any these types of agreements with third parties. FERC or a state commission could investigate our rates on its own initiative or at the urging of a third party if the third party is either a current shipper or is able to show that it has a substantial economic interest in our tariff rate level.

If our rate levels were investigated, the inquiry could result in a comparison of our rates to those charged by others or to an investigation of our costs, including, but not limited to:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

If FERC or a state commission were to determine that our rates were or had become unjust and unreasonable, we could be ordered to reduce rates prospectively and pay refunds and/or reparations to shippers.

*FERC-Regulated Natural Gas Pipelines.* Our natural gas pipeline operations are subject to federal, state and local regulatory authorities. Specifically, we have FERC gas tariffs on file for MarkWest New Mexico, L.L.C. and MarkWest Pioneer, L.L.C. with respect to our Hobbs Pipeline and the Arkoma Connector Pipeline. These pipelines are subject to regulation by FERC, and it is possible that we may have additional gas pipelines that may require such tariffs and may be subject to similar regulation in the future. FERC regulation of jurisdictional natural gas pipelines extends to various matters including:

- rates and rate structures;
- return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction, expansion, operation and disposition of assets;
- affiliate interactions; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act (“NGA”), FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. As noted in the list above, FERC’s authority to

regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services and various other matters. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable, or unduly discriminatory by FERC. In addition, FERC prohibits FERC-regulated natural gas companies from unduly preferring, or unduly discriminating against, any person with respect to pipeline rates or terms and conditions of service or other matters. The rates and terms and conditions for the Hobbs Pipeline and the Arkoma Connector Pipeline can be found in their respective FERC-approved tariffs and in negotiated rate agreements entered into under those tariffs. Pursuant to FERC's jurisdiction, existing rates and/or other tariff provisions may be challenged (e.g., by complaint) and rate increases proposed by the pipeline or other tariff changes may be challenged (e.g., by protest). We also cannot be assured that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules, rights of access, capacity and other issues that impact natural gas facilities. Any successful complaint or protest related to our facilities could have an adverse impact on our revenues.

As noted above (under "Common Carrier Liquids Pipeline Operations"), FERC is reviewing its policies with respect to the inclusion of income tax allowances in cost-of-service rates. A Notice of Inquiry into these issues was issued by FERC on December 15, 2016. The outcome of this inquiry could affect the rates that interstate natural gas pipelines are permitted to charge.

*Energy Policy Act of 2005.* On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("2005 EAct"). Under the 2005 EAct, FERC may impose civil penalties for violations of statutory and regulatory requirements. The 2005 EAct also amends the NGA to add an anti-market manipulation provision, which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. FERC issued Order No. 670 to implement the anti-market manipulation provision of the 2005 EAct. This order makes it unlawful for gas pipelines and storage companies that provide interstate services to: (i) directly or indirectly, use or employ any device, scheme or artifice to defraud in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's enforcement authority.

*Standards of Conduct.* FERC has adopted affiliate standards of conduct applicable to interstate natural gas pipelines and certain other regulated entities, defined as "Transmission Providers." Under these rules, a Transmission Provider becomes subject to the standards of conduct if it provides service to affiliates that engage in marketing functions (as defined in the standards). If a Transmission Provider is subject to the standards of conduct, the Transmission Provider's transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider's marketing function employees (including the marketing function employees of any of its affiliates). The Transmission Provider must also comply with certain posting and other requirements.

*Market Transparency Rulemakings.* In 2007, FERC issued Order 704, as amended and clarified in subsequent orders on rehearing, whereby wholesale buyers and sellers of more than 2.2 MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704.

*Gas-Electric Coordination.* In 2015, FERC issued Order 587-W and adopted new standards designed to improve coordination between the gas and electric industries. Among other things, the new standards revise the

nomination timelines used by interstate natural gas pipelines. Interstate natural gas pipelines were required to implement the new standards in 2016. FERC continues to evaluate other measures to improve coordination between the gas and electric industries, and the adoption of any such measures may impact FERC's regulation of jurisdictional natural gas pipelines.

*Intrastate Natural Gas Pipeline Regulation.* Some of our intrastate gas pipeline facilities are subject to various state laws and regulations that affect the rates we charge and terms of service. Although state regulation is typically less onerous than FERC, state regulation typically requires pipelines to charge just and reasonable rates and to provide service on a non-discriminatory basis. The rates and service of an intrastate pipeline generally are subject to challenge by complaint. Additionally, FERC has adopted certain regulations and reporting requirements applicable to intrastate natural gas pipelines (and Hinshaw natural gas pipelines) that provide certain interstate services subject to FERC's jurisdiction. We could become subject to such regulations and reporting requirements in the future to the extent that any of our intrastate pipelines were to begin providing, or were found to provide, such interstate services.

Additional proposals and proceedings that might affect the natural gas industry periodically arise before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than other midstream natural gas companies with whom we compete.

*Natural Gas Gathering Pipeline Regulation.* Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC if the primary function of the facilities is gathering natural gas. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. We own a number of facilities that we believe establish the pipeline's status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so we cannot provide assurance that FERC will not at some point assert that these facilities are within its jurisdiction or that such an assertion would not adversely affect our results of operations and revenues. In such a case, we would possibly be required to file a tariff with FERC, provide a cost justification for the transportation charge and obtain certificate(s) of public convenience and necessity for the FERC-regulated pipelines, and comply with additional FERC requirements.

In the states in which we operate, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental and, in some circumstances, open access, non-discriminatory take requirement and complaint-based rate regulation. For example, some of our natural gas gathering facilities are subject to state ratable take and common purchaser statutes and regulations. Ratable take statutes and regulations generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes and regulations generally require gatherers to purchase gas 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. Although state regulation is typically less onerous than at FERC, these statutes and regulations have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. 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 or regulated as a public utility. Our gathering operations also may be or become subject to safety and operational regulations and permitting requirements relating to the design, siting, installation, testing, construction, operation, replacement and management of gathering facilities. 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.

Currently, PHMSA is evaluating possible changes to the scope and applicability of 49 C.F.R. Part 192, which governs construction standards and operation of certain natural gas gathering pipelines. The changes being considered include, but are not limited to, more stringent construction standards for remote facilities, as well as additional record-keeping requirements. Depending upon the nature of the final rule-making, those could have an impact upon MPLX LP operations.

*Natural Gas Processing.* Our natural gas processing operations are not presently subject to FERC or state rate regulation. There can be no assurance that our processing operations will continue to be exempt from FERC regulation in the future. In addition, although the processing facilities may not be directly related, other laws and regulations may affect the availability of natural gas for processing, such as state regulation of production rates and maximum daily production allowances from gas wells, which could impact our processing business.

*NGL Pipelines.* We have constructed various NGL product pipelines to transport NGL products, some of which are regulated by FERC, and we may elect to construct additional such pipelines in the future that may be subject to these same regulatory requirements. Pipelines providing transportation of NGLs in interstate commerce are subject to the same regulatory requirements as common carrier petroleum pipelines. See “Common Carrier Liquids Pipeline Operations” above. We have several NGL pipelines that carry NGLs owned by us between our processing and fractionation facilities that cross state lines. We do not have FERC tariffs on file for these pipelines because we believe they are not subject to FERC requirements or that they would otherwise meet the qualifications for a waiver from FERC’s filing and reporting requirements. We cannot, however, provide assurance that FERC will not, at some point, either at the request of other entities or on its own initiative, assert that some or all of these pipelines are subject to FERC requirements for interstate petroleum pipelines and not exempt from its filing and reporting requirements. We also cannot provide assurance that such an assertion would not adversely affect our results of operations. In the event FERC were to determine that these NGL pipelines are subject to FERC requirements for common carrier pipelines or otherwise would not qualify for a waiver from FERC’s applicable regulatory requirements, we would likely be required to file a tariff with FERC for the pipelines, provide a cost justification for their transportation rates, and provide service to all potential shippers without undue discrimination, and we may also be subject to fines, penalties or other sanctions.

Our NGL pipelines are also subject to safety regulation by the DOT under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines. Currently, PHMSA is evaluating possible changes to the scope and applicability of 49 C.F.R. Part 195m, including, among other things, expansion of reporting obligations, additional inspection requirements, and expansion of the use of leak detection systems. Depending upon the nature of the final rule-making, those could have an impact upon MPLX LP operations. Our NGL pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities.

*Propane Regulation.* National Fire Protection Association Pamphlets 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. 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.

*Marine Transportation.* Our marine transportation business is subject to regulation by the USCG, federal laws, including the Jones Act, state laws and certain international conventions, as well as numerous environmental

regulations. The majority of our vessels are subject to inspection by the USCG and carry certificates of inspection. The crews employed aboard the vessels are licensed or certified by the USCG. We are required by various governmental agencies to obtain licenses, certificates and permits for our vessels.

Our marine transportation business competes principally in markets subject to the Jones Act, a federal cabotage law that restricts domestic marine transportation in the United States to vessels built and registered in the United States, and manned and owned by United States citizens. We presently meet all of the requirements of the Jones Act for our vessels. The loss of Jones Act status could have a significant negative effect on us. The requirements that our vessels be United States built and manned by United States citizens, the crewing requirements and material requirements of the USCG, and the application of United States labor and tax laws increases the cost of United States flag vessels when compared with comparable foreign flag vessels. Our marine transportation business could be adversely affected if the Jones Act were to be modified so as to permit foreign competition that is not subject to the same United States government imposed burdens. Since the events of September 11, 2001, the United States government has taken steps to increase security of United States ports, coastal waters and inland waterways. We believe that it is unlikely that the current cabotage provisions of the Jones Act would be modified or eliminated in the foreseeable future.

The Secretary of Homeland Security is vested with the authority and discretion to waive the Jones Act to such extent and upon such terms as the Secretary may prescribe whenever the Secretary deems that such action is necessary in the interest of national defense. For example, the Secretary has waived the Jones Act generally or with respect to the transportation of certain petroleum products for limited periods of time and in limited areas following the occurrence of certain natural disasters such as hurricanes. Waivers of the Jones Act, whether in response to natural disasters or otherwise, could result in increased competition from foreign tank vessel operators, which could negatively impact our marine transportation business.

*Pipeline Interconnections.* One or more of our plants include pipeline interconnections to, or incidental gathering pipelines that connect the plants to, interstate pipelines. These pipeline interconnections are an integral part of our facilities and are not currently being used, nor can they be used in the future, by any third party due to their origin points at our proprietary facilities. Therefore, we believe these pipeline interconnections are part of our plant facilities and are not subject to the jurisdiction of FERC. In the event that FERC were to determine that these pipeline interconnections were subject to its jurisdiction, we believe the pipelines would qualify for a waiver from most FERC reporting and filing requirements. In the event that FERC were to determine that the pipeline interconnections did not qualify for such waivers, we would likely be required to file a tariff with FERC for the pipeline interconnections, provide a cost justification for their transportation rates and provide service to all potential shippers without undue discrimination. In such event, we may experience increased operating costs and reduced revenues.

*Security.* Certain of our facilities have been preliminarily classified as subject to the Department of Homeland Security Chemical Facility Anti-Terrorism Standards. In addition, we have several facilities that are subject to the United States Coast Guard's Maritime Transportation Security Act, and a number of other facilities that are subject to the Transportation Security Administration's Pipeline Security Guidelines and are designated as "Critical Facilities." The Transportation Security Administration Security Guidelines are subject to change without formal regulatory proposal and review. We have an internal inspection program designed to monitor and ensure compliance with all of these requirements. We believe that we are in material compliance with all applicable laws and regulations regarding the security of our facilities.

## **ENVIRONMENTAL REGULATION**

### **General**

Our processing and fractionation plants, storage facilities, pipelines and associated facilities are subject to multiple obligations and potential liabilities under a variety of federal, regional, state and local laws and regulations relating to environmental protection. Such environmental laws and regulations may affect many

aspects of our present and future operations, including for example, requiring the acquisition of permits or other approvals to conduct regulated activities that may impose burdensome conditions or potentially cause delays, restricting the manner in which we handle or dispose of our wastes, limiting or prohibiting construction or other activities in environmentally sensitive areas such as wetlands or areas inhabited by threatened or endangered species, requiring us to incur capital costs to construct, maintain and/or upgrade processes, equipment and/or facilities, restricting the locations in which we may construct our compressor stations and other facilities and/or requiring the relocation of existing stations and facilities, and requiring remedial actions to mitigate any pollution that might be caused by our operations or attributable to former operations. Spills, releases or other incidents may occur in connection with our active operations or as a result of events outside of our reasonable control, which incidents may result in non-compliance with such laws and regulations. Any failure to comply with these legal requirements may expose us to the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of remedial or corrective actions and the issuance of orders enjoining or limiting some or all of our operations.

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and the cost of continued compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial condition. We cannot assure, however, that existing environmental laws and regulations will not be reinterpreted or revised or that new environmental laws and regulations will not be adopted or become applicable to us. Generally speaking, the trend in environmental law is to place more restrictions and limitations on activities that may be perceived to adversely affect the environment, which may cause significant delays in obtaining permitting approvals for our facilities, result in the denial of our permitting applications, or cause us to become involved in time consuming and costly litigation. Thus, there can be no assurance as to the amount or timing of future expenditures for compliance with environmental laws and regulations, permits and permitting requirements or remedial actions pursuant to such laws and regulations, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional environmental requirements may result in increased compliance and mitigation costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, and could have a material adverse effect on our business, financial condition, results of operations and cash flow. We may not be able to recover some or any of these costs from insurance. Such revised or additional environmental requirements may also result in substantially increased costs and material delays in the construction of new facilities or expansion of our existing facilities, which may materially impact our ability to meet our construction obligations with our producer customers.

Under the omnibus agreement, MPC has agreed to indemnify us for all known and certain unknown environmental liabilities that are associated with the ownership or operation of our assets that we acquired from MPC and due to occurrences on or before the closing of the Initial Offering. Indemnification for any unknown environmental liabilities will be limited to liabilities due to occurrences on or before the closing of the Initial Offering and identified prior to the fifth anniversary of the closing of the Initial Offering, and will be subject to an aggregate deductible of \$500,000 before we are entitled to indemnification for losses incurred. Any other liabilities for which MPC has agreed to indemnify us are not subject to a deductible before we are entitled to indemnification. There is no limit on the amount for which MPC has agreed to indemnify us under the omnibus agreement once we meet the deductible, if applicable. Neither we nor our general partner have any contractual obligation to investigate or identify any such unknown environmental liabilities. We have agreed to indemnify MPC for events and conditions associated with the ownership or operation of our assets due to occurrences after the closing of the Initial Offering and for environmental liabilities associated with or arising from our ownership or operation of the assets on or after the closing of the Initial Offering, in each case, to the extent MPC is not required to indemnify us for such liabilities. Pipe Line Holdings has agreed to indemnify MPC for events and conditions associated with the operations of the Pipe Line Holdings assets that occur after the closing of the Initial Offering. Liabilities for which we and Pipe Line Holdings have agreed to indemnify MPC pursuant to the omnibus agreement are not subject to a deductible before MPC is entitled to indemnification. There is no limit on the amount for which we or Pipe Line Holdings has agreed to indemnify MPC under the omnibus agreement.

## **Hazardous Substances and Wastes**

A comprehensive framework of environmental laws and regulations governs our operations as they relate to the possible release of hazardous substances or non-hazardous or hazardous wastes into soils, groundwater and surface water and measures taken to mitigate pollution into the environment. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (“CERCLA”), also known as the “Superfund” law, as well as comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include current and prior owners or operators of a site where a release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances released from the site. Under CERCLA, these persons may be subject to strict joint and several liability for the costs of removing or remediating hazardous substances that have been released into the environment and for restoration costs and damages to natural resources. Additionally, neighboring landowners and other third parties can file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. While we generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA or similar state statutes, we do not believe that we have any current material liability for cleanup costs under such laws or for third-party claims. We also may incur liability under the Resource Conservation and Recovery Act, as amended (“RCRA”), and comparable or more stringent state statutes, which impose requirements relating to the handling and disposal of non-hazardous and hazardous wastes. In the course of our operations, we generate some amount of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. It is possible that some wastes generated by us that are currently classified as non-hazardous wastes may in the future be designated as hazardous wastes, resulting in the wastes being subject to more rigorous and costly transportation, storage, treatment and disposal requirements.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for natural gas gathering, processing and transportation, for NGL fractionation or for the storage, gathering and transportation of crude oil. Although waste disposal practices within the NGL industry and other oil and natural gas related industries have been enhanced and improved over the years, it is possible that petroleum hydrocarbons and other non-hazardous or hazardous wastes may have been disposed of by prior owners or operators on or under these various properties owned or leased by us during the operating history of those facilities. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination.

## **Ongoing Remediation and Indemnification from Third Parties**

The prior third-party owner or operator of our Cobb, Boldman, Kenova, Kermit and Majorsville facilities, has been, or is currently involved in, certain investigatory or remedial activities with respect to the real property underlying these facilities. The third party or, in the case of the Kermit Complex, its successor in interest, has accepted sole liability and responsibility for, and indemnifies us against those activities or any other environmental condition related to the real property prior to the effective dates of our lease or purchase of the real property that are not contributed to by us. In addition, the third party, or in the case of the Kermit Complex, its successor in interest, has agreed to perform all the required response actions at its expense in a manner that minimizes interference with our use of the properties. We understand that to date, all required actions have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

The prior third-party owner and/or operator of certain facilities on the real property on which our rail facility is constructed near Houston, Pennsylvania has been, or is currently involved in, investigatory or remedial activities related to acid mine drainage (“AMD”) with respect to the real property underlying these facilities. These



investigatory and remedial obligations arise out of an arrangement entered into between the Pennsylvania Department of Environmental Protection and the third party, which has accepted liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations. In addition, the third party has agreed to perform all of the required response actions at its expense in a manner that minimizes interference with our use of the property. We understand that to date, all actions required under these agreements have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

We are also entitled to indemnification from MPC for assets we acquired from MPC in our Initial Offering, as further described above under “General”. In addition, from time to time, we have acquired, and we may acquire in the future, facilities from third parties or MPC that previously have been or currently are the subject of investigatory, remedial or monitoring activities relating to environmental matters. The terms of each acquisition will vary, and in some cases we may receive contractual indemnification from the prior owner or operator for some or all of the liabilities relating to such matters, and in other cases we may agree to accept some or all of such liabilities. We do not believe that the portion of any such liabilities that the Partnership may bear with respect to any such properties previously acquired by the Partnership will have a material adverse impact on our financial condition or results of operations.

### **Water Discharges**

Our operations can result in the discharge of pollutants, including crude oil and refined products. Regulations under the Water Pollution Control Act of 1972 (“Clean Water Act”), Oil Pollution Act of 1990 (“OPA-90”) and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. Such discharges are prohibited, except in accord with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law and some state laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, oil overflow, rupture or leak. For example, the Clean Water Act requires us to maintain Spill Prevention Control and Countermeasure (“SPCC”) plans at many of our facilities. We maintain numerous discharge permits for facilities and vessels as required under the National Pollutant Discharge Elimination System program of the Clean Water Act and have implemented systems to oversee our compliance efforts. Any unpermitted release of pollutants, including oil, NGLs or condensates, could result in administrative, civil and criminal penalties as well as significant remedial obligations. In addition, the Clean Water Act and analogous state law may also require individual permits or coverage under general permits for discharges of storm water from certain types of facilities, but these requirements are subject to several exemptions specifically related to oil and natural gas operations and facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit. We conduct regular review of the applicable laws and regulations, and maintain discussions with the various federal, state and local agencies with regard to the application of those laws and regulations to our facilities, including the permitting process and categories of applicable permits for storm water or other discharges, stream crossings and wetland disturbances that may be required for the construction or operation of certain of our facilities in the various states.

In addition, the transportation and storage of crude oil and refined products over and adjacent to water involves risk and subjects us to the provisions of OPA-90 and related state requirements. Among other requirements, OPA-90 requires the owner or operator of a tank vessel, a facility or a pipeline to maintain an emergency plan to respond to releases of oil or hazardous substances. Also, in case of any such release, OPA-90 requires the responsible company to pay resulting removal costs and damages. OPA-90 also provides for civil penalties and imposes criminal sanctions for violations of its provisions. We operate facilities at which releases of oil and hazardous substances could occur. We have implemented emergency oil response plans for all of our components and facilities covered by OPA-90 and we have established SPCC plans for facilities subject to Clean Water Act SPCC requirements.

Construction or maintenance of our plants, compressor stations, pipelines, barge dock and storage facilities may impact wetlands, which are also regulated under the Clean Water Act by the EPA, the United States Army Corps of Engineers and state water quality agencies. Regulatory requirements governing wetlands (including associated mitigation projects) may result in the delay of our projects while we obtain necessary permits and may increase the cost of new projects and maintenance activities. We believe that we are in substantial compliance with the Clean Water Act and analogous state laws. However, there is no assurance that we will not incur material increases in our operating costs or delays in the construction or expansion of our facilities because of future developments, the implementation of new laws and regulations, the reinterpretation of existing laws and regulations, or otherwise, including, for example, increased construction activities, potential inadvertent releases arising from pursuing borings for pipelines, and earth slips due to heavy rain and/or other causes.

### **Hydraulic Fracturing**

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing and fractionation services with respect to natural gas, oil and NGLs produced by our producer customers as a result of such operations. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and issued in May 2014 its Advance Notice of Proposed Rulemaking to solicit input on the possible Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in March 2015, the Bureau of Land Management (“BLM”) published its final rule setting new standards for hydraulic fracturing on onshore federal and Indian lands. The final rules have been challenged and, in June 2016, the United States District Court for Wyoming set aside these BLM rules, holding that the BLM lacked the statutory authority to regulate the hydraulic fracturing process. In addition, Congress has from time to time considered legislation to provide for additional regulation of hydraulic fracturing, and some states have adopted, and other states are considering adopting, laws and/or regulations that could impose more stringent permitting, disclosure and well construction requirements on natural gas and oil drilling activities or prohibit hydraulic fracturing altogether, similar to the State of New York. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. In the event that new or more stringent federal, state or local legal restrictions relating to natural gas drilling activities or to the hydraulic fracturing process are adopted in areas where our producer customers operate, those customers could incur potentially significant added costs to comply with such hydraulic fracturing-related requirements and experience delays or curtailment in the pursuit of production or development activities, which could reduce demand for our gathering, transportation and processing services and/or our NGL fractionation services.

In addition, certain governmental reviews are underway that focus on potential environmental aspects of hydraulic fracturing practices. Most notably, in December 2016, the EPA released its final assessment of the impacts of hydraulic fracturing on drinking water. These studies could spur initiatives to further regulate hydraulic fracturing that could delay or curtail production of natural gas, and thus reduce demand for our midstream services.

### **Air Emissions**

The Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, including processing plants and compressor stations, and also impose various monitoring and reporting requirements. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements, utilize specific equipment or technologies to control

emissions, or aggregate two or more of our facilities into one application for permitting purposes. We believe that our operations are in substantial compliance with applicable air permitting and control technology requirements. However, we may be required to incur capital expenditures in the future for installation of air pollution control equipment and encounter construction or operational delays while applying for, or awaiting the review, processing and issuance of new or amended permits, and we may be required to modify certain of our operations which could increase our operating costs. For example, the EPA issued final regulations in October 2015 to revise the National Ambient Air Quality Standard for ozone to 70 parts per billion, or ppb, for both the eight-hour primary and secondary standards protective of public health and public welfare. These standards, which are currently again under review, could require states to implement new more stringent regulations, which could apply to our operations and those of our customers. The EPA is currently considering revisions to regulations or interpretations of regulations regarding permitting and performance standards for methane emissions from new and modified oil and gas production and natural gas processing and transmission facilities, any of which could require additional capital expenditures, increase our operating costs or otherwise restrict our operations. Additionally, in 2015, EPA finalized regulations to revise existing refinery air emissions standards, which require additional controls, lower emission standards and require ambient air monitoring. These revised refinery standards affect refineries, including MPC's refineries from which we receive significant revenues. To the extent capital expenditures required to comply with new legislative and regulatory requirements have a material effect on MPC or our other customers, they could have a material effect on our business and results of operations.

### **Climate Change**

As a consequence of an EPA administrative conclusion that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") into the ambient air endangers public health and welfare, the EPA adopted regulations establishing the Prevention of Significant Deterioration ("PSD") construction and Title V operating permit programs for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Although the EPA's PSD and Title V permit programs are limited to large stationary sources of criteria pollutant emissions, states may seek to adopt their own permitting programs under state laws that require permit reviews of large stationary sources emitting only GHGs. If we were to become subject to Title V and PSD permitting requirements due to non-GHG criteria pollutants, or if the EPA implemented more stringent permitting requirements relating to GHG emissions without regard to non-GHG criteria pollutants, or if states adopt their own permitting programs that require permit reviews based on GHG emissions, we may be required to install "best available control technology," to the extent such technology is available, to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future. In addition, we may experience substantial delays or possible curtailment of construction or projects in connection with applying for, obtaining or maintaining preconstruction and operating permits, we may encounter limitations on the design capacities or size of facilities, and we may incur material increases in our construction and operating costs. We are monitoring GHG emissions from certain of our facilities in accordance with current GHG emissions reporting requirements in a manner that we believe is in substantial compliance with applicable reporting obligations.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and it is possible that such legislation could be enacted in the future. In the absence of federal climate legislation in the United States, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. The EPA issued final rules in May 2016 aimed at minimizing fugitive emissions and establishing methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the

Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. This rule is currently being challenged in court by various affected states. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil and natural gas produced by our exploration and production customers that, in turn, could reduce the demand for our services and thus adversely affect our cash available for distribution to our unitholders.

### **Endangered Species Act and Migratory Bird Treaty Act Considerations**

The federal Endangered Species Act ("ESA") and analogous state laws regulate activities that may affect endangered or threatened species, including their habitats. If protected species are located in areas where we propose to construct new gathering or transportation pipelines, processing or fractionation facilities, or other infrastructure, such work could be prohibited or delayed in certain of those locations or during certain times, when our operations could result in a taking of the species or destroy or adversely modify critical habitat that has been designated for the species. We also may be obligated to develop plans to avoid potential takings of protected species and provide mitigation to offset the effects of any unavoidable impacts, the implementation of which could materially increase our operating and capital costs. Existing laws, regulations, policies and guidance relating to protected species may also be revised or reinterpreted in a manner that further increases our construction and mitigation costs or restricts our construction activities. Additionally, construction and operational activities could result in inadvertent impact to a listed species and could result in alleged takings under the ESA, exposing the Partnership to civil or criminal enforcement actions and fines or penalties. Moreover, as a result of a settlement approved by the United States District Court for the District of Columbia in September 2011, the United States Fish and Wildlife Service ("FWS") is required to make a determination on listing numerous species as endangered or threatened under the ESA by completion of the agency's 2017 fiscal year. For example, in April 2015, the FWS published a final rule listing the Northern Long Eared Bat as threatened under the ESA. In another example, in September 2016, the FWS announced the listing of the Eastern Massasauga rattlesnake as a threatened species under the ESA. In addition, in January 2017, FWS issued a final rule listing the rusty patched bumblebee as an endangered species effective in February 2017. All of these species, along with the other endangered species such as the Indiana Bat and American Burying Beetle, are in areas in which we operate. The listing of these or other species as threatened or endangered in areas where we conduct operations or plan to construct pipelines or facilities may cause us to incur increased costs arising from species protection measures or could result in delays in, or prohibit, the construction of our facilities or limit our customer's exploration and production activities, which could have an adverse impact on demand for our midstream operations.

The Migratory Bird Treaty Act implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without authorization. If there is the potential to adversely affect migratory birds as a result of our operations or construction activities, we may be required to seek authorization to conduct those operations or construction activities, which may result in specified operating or construction restrictions on a temporary, seasonal, or permanent basis in affected areas and thus have an adverse impact on our ability to provide timely gathering, processing or fractionation services to our exploration and production customers.

### **Pipeline Safety Matters**

Our assets are subject to increasingly strict safety laws and regulations. The transportation and storage of natural gas and crude oil and refined products involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages and significant business interruption. The DOT has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our pipeline assets. These regulations contain requirements for the development and implementation of pipeline integrity

management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

We are subject to regulation by the DOT under the Hazardous Liquid Pipeline Safety Act of 1979, also known as the HLPESA. The HLPESA delegated to the DOT the authority to develop, prescribe and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline. Congress also enacted the Pipeline Safety Act of 1992, also known as the PSA, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, required regulations be issued to define the term “gathering line” and establish safety standards for certain “regulated gathering lines,” and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in High Consequence Areas (“HCAs”), defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act, also known as the APSPA, which limited the operator identification requirement mandate to pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, also known as the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management. We are also subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal pipeline safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

The DOT has delegated its authority under these statutes to the PHMSA, which administers compliance with these statutes and has promulgated comprehensive safety standards and regulations for the transportation of natural gas by pipeline (49 Code of Federal Regulations (“CFR”) Part 192), as well as hazardous liquids by pipeline (49 CFR Part 195), including regulations for the design and construction of new pipelines or those that have been relocated, replaced or otherwise changed (Subparts C and D of 49 CFR, Part 195); pressure testing of new pipelines (Subpart E of 49 CFR Part 195); operation and maintenance of pipelines, including inspecting and reburial of pipelines in the Gulf of Mexico and its inlets, establishing programs for public awareness and damage prevention, managing the integrity of pipelines in HCAs and managing the operation of pipeline control rooms (Subpart F of 49 CFR Part 195); protecting steel pipelines from the adverse effects of internal and external corrosion (Subpart H of 49 CFR Part 195); and integrity management requirements for pipelines in HCAs (49 CFR 195.452). PHMSA has undertaken a number of initiatives to reevaluate its pipeline safety regulations. We do not anticipate that we would be impacted by these regulatory initiatives to any greater degree than other similarly situated competitors.

We monitor the structural integrity of our pipelines through a program of periodic internal assessments using high resolution internal inspection tools, as well as hydrostatic testing and direct assessment, that conform to federal standards. We accompany these assessments with a review of the data and repair anomalies, as required, to ensure the integrity of the pipeline. We then utilize sophisticated risk algorithms and a comprehensive data integration effort to ensure that the highest risk pipelines receive the highest priority for scheduling subsequent integrity assessments. We use external coatings and impressed current cathodic protection systems to protect against external corrosion. We conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards. We continually monitor, test and record the effectiveness of these corrosion inhibiting systems.

## **Pipeline Permitting**

Pipeline construction and expansion is subject to government permitting and involves numerous regulatory environmental, political and legal uncertainties, most of which are beyond our control. We believe our operations are in substantial compliance with our permits.

## **Facility Safety**

At manned facilities, the workplaces associated with the processing and storage facilities and the pipelines we operate are also subject to oversight pursuant to the federal Occupational Safety and Health Act, as amended (“OSHA”), as well as comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard-communication standard requires that we maintain information about hazardous materials used or produced in operations, and that this information be provided to employees, state and local government authorities and citizens. We believe that we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

At unmanned facilities, the EPA’s Risk Management Planning requirements at regulated facilities are intended to protect the safety of the surrounding public. The application of these regulations, which are often unclear, can result in increased compliance expenditures.

In general, we expect industry and regulatory safety standards to become stricter over time, resulting in increased compliance expenditures. While these expenditures cannot be accurately estimated at this time, we do not expect such expenditures will have a material adverse effect on our results of operations.

Notwithstanding the foregoing, PHMSA and one or more state regulators, including the Texas Railroad Commission, have recently sought to expand the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities in order to assess compliance with hazardous liquids pipeline safety requirements. These recent actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities may be required to make operational changes or modifications at their facilities to meet standards beyond current requirements. These changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation.

## **Product Quality Standards**

Refined products and other hydrocarbon-based products that we transport are generally sold by us or our customers for consumption by the public. Various federal, state and local agencies have the authority to prescribe product quality specifications for products. The EPA established sulfur specifications for natural gasoline sold as certified ethanol denaturant effective January 1, 2017. The EPA has also proposed product quality specification for natural gasoline used for blendstock in ethanol flex fuel. The EPA has also established product quality specifications related to butane blending, which we perform at certain of our light products storage facilities. Changes in product quality specifications or blending requirements could reduce our throughput volumes, require us to incur additional handling costs or require capital expenditures. For example, different product specifications for different markets affect the fungibility of the products in our system and could require the construction of additional storage. In addition, changes in the product quality of the products we receive on our product pipelines could reduce or eliminate our ability to blend products.

## **EMPLOYEES**

We are managed and operated by the board of directors and executive officers of MPLX GP, our general partner. Our general partner has the sole responsibility for providing the employees and other personnel necessary to

conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner. Our general partner and its affiliates have approximately 4,300 full-time employees that provide services to us under our employee services agreements. We believe that our general partner and its affiliates have a satisfactory relationship with those employees.

#### **AVAILABLE INFORMATION**

General information about MPLX LP and our general partner, MPLX GP, including Governance Principles, Audit Committee Charter, Conflicts Committee Charter and Certificate of Limited Partnership, can be found at <http://www.mplx.com>. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available in this same location.

MPLX LP uses its website, [www.mplx.com](http://www.mplx.com), as a channel for routine distribution of important information, including news releases, analyst presentations and financial information. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. These documents are also available in hard copy, free of charge, by contacting our Investor Relations office. In addition, our website allows investors and other interested persons to sign up to automatically receive email alerts when we post news releases and financial information on our website. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

## Item 1A. Risk Factors

*You should carefully consider each of the following risks and all the other information set forth elsewhere in this Annual Report on Form 10-K in evaluating us and our common units. Some of these risks relate principally to our business, the business and operations of MPC and the industry in which we operate, while others relate principally to tax matters, and ownership of our common units and the securities markets generally.*

*Our business, financial condition, results of operations or cash flows could be materially and adversely affected by these risks, and, as a result, the trading price of our common units could decline.*

### Risks Relating to Our Business

#### **Our substantial debt and other financial obligations could impair our financial condition, results of operations and cash flow, and our ability to fulfill our debt obligations.**

We have significant debt obligations, which totaled \$7.7 billion as of December 31, 2017, including amounts outstanding under our loan agreement with MPC Investment, and we may incur significant additional debt obligations in the future. For example, in February 2018, we issued an additional \$5.5 billion aggregate principal amount of senior notes. Our existing and future indebtedness may impose various restrictions and covenants on us that could have, or the incurrence of such debt could otherwise result in, material adverse consequences, including:

- We may have difficulties obtaining additional financing for working capital, capital expenditures, acquisitions, or general partnership purposes on favorable terms, if at all, or our cost of borrowing may increase. Our funds available for operations, business opportunities and distributions to unitholders will also be reduced by that portion of our cash flow required to make interest payments on our debt.
- We may be at a competitive disadvantage compared to our competitors who have proportionately less debt, or we may be more vulnerable to, and have limited flexibility to respond to, competitive pressures or a downturn in our business or the economy generally.
- If our operating results are not sufficient to service our indebtedness, we may be required to reduce our distributions, reduce or delay our business activities, investments or capital expenditures, sell assets or issue equity, which could materially and adversely affect our financial condition, results of operations, cash flows and ability to make distributions to unitholders, as well as the trading price of our common units.
- The operating and financial restrictions and covenants in our revolving credit facility and any future financing agreements could restrict our ability to finance our operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make distributions to our unitholders. Our ability to comply with these covenants may be impaired from time to time if the fluctuations in our working capital needs are not consistent with the timing for our receipt of funds from our operations.
- If we fail to comply with our debt obligations and an event of default occurs, our lenders could declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable, which may trigger defaults under our other debt instruments or other contracts. Our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment.

#### **Global economic conditions may have adverse impacts on our business and financial condition and adversely impact our ability to access capital markets on acceptable terms.**

Changes in economic conditions could adversely affect our financial condition and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, government spending, strength of U.S. currency versus other international currencies, consumer confidence and debt levels, retail trends, inflation and foreign currency exchange rates, may generally affect our business.



Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs and higher tax rates may adversely affect demand for natural gas, NGLs and crude oil. Also, any tightening of the capital markets could adversely impact our ability to execute our long-term organic growth projects and meet our obligations to our customers and limit our ability to raise capital and, therefore, have an adverse impact on our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

**A significant decrease or delay in oil and natural gas production in our areas of operation, whether due to sustained declines in oil, natural gas and NGL prices, natural declines in well production, or otherwise, may adversely affect our revenues, financial condition, and cash available for distribution.**

A significant portion of our operations are dependent upon production from oil and natural gas reserves and wells, which will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels and the utilization rate of our facilities, we must continually obtain new oil, natural gas, NGL and refined product supplies, which depends in part on the level of successful drilling activity near our facilities.

We have no control over the level of drilling activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, drilling costs per mcf or barrel, demand for hydrocarbons, operational challenges, access to downstream markets, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital. Because of these factors, even if new oil or natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of oil or natural gas to replace the natural decline in volumes from existing wells, throughput on our pipelines and the utilization rates of our facilities would decline, which could have a material adverse effect on our business, results of operations and financial condition and could reduce our ability to make distributions to our unitholders.

Decreases in energy prices can decrease drilling activity, production rates and investments by third parties in the development of new oil and natural gas reserves. The prices for oil, natural gas and NGLs depend upon factors beyond our control, including global and local demand, production levels, changes in interstate pipeline gas quality specifications, imports and exports, seasonality and weather conditions, economic and political conditions domestically and internationally and governmental regulations. Sustained periods of low prices could result in producers also significantly curtailing or limiting their oil and gas drilling operations which could substantially delay the production and delivery of volumes of oil, gas and NGLs to our facilities and adversely affect our revenues and cash available for distribution. This impact may also be exacerbated due to the extent of our commodity-based contracts, which are more directly impacted by changes in gas and NGL prices than our fee-based contracts due to frac spread exposure and may result in operating losses when natural gas becomes more expensive on a Btu equivalent basis than NGL products. In addition, our purchase and resale of gas and NGLs in the ordinary course exposes us to significant risk of volatility in gas or NGL prices due to the potential difference in the time of the purchases and sales and the potential difference in the price associated with each transaction, and direct exposure may also occur naturally as a result of our production processes. The significant volatility in natural gas, NGL and oil prices could adversely impact our unit price, thereby increasing our distribution yield and cost of capital. Such impacts could adversely impact our ability to execute our long-term organic growth projects, satisfy our obligations to our customers, and make distributions to unitholders at intended levels, and may also result in non-cash impairments of long-lived assets or goodwill or other-than-temporary non-cash impairments of our equity method investments.

**Our business plan and growth strategy requires, among other matters, access to new capital. An increased cost of capital could impair our ability to grow, our ability to make distributions to unitholders at our intended levels and trigger us to impair our goodwill and intangible assets.**

Our ability to successfully operate our business, generate sufficient cash to pay the quarterly cash distributions to our unitholders and to allow for growth of our business and the growth of our distributions is subject to a number of risks and uncertainties, including economic and competitive factors beyond our control, which may impair our access to new capital. If the cost of capital becomes too expensive, we may not be able to raise the necessary funds from the equity market on satisfactory terms, if at all. We may be required to consider alternative financing strategies such as the formation of joint ventures or the sale of non-strategic assets, which may not provide the necessary capital, and our ability to develop or acquire strategic and accretive assets and finance growth projects will be limited. Factors that influence our cost of capital include market conditions, including our common unit price and the resultant distribution yield. When the price of our common units decreases, the resultant distribution yield increases, and our cost of capital increases accordingly. A significant drop in our unit price could also trigger an impairment of our goodwill and intangible assets. A significant decline in oil prices, such as the decline that occurred in 2015 and 2016, can impact our common unit price. Although oil prices have since recovered to some extent, there is no assurance that this recovery will continue. The high and the low closing market price of our common units in 2017 ranged from a high of \$38.86 to a low of \$31.10. Given the significant change in MLP valuations and the resultant higher distribution yield environment the sector has experienced since 2015, our cost of capital has increased, which could impair our ability to grow our business and make distributions to unitholders at intended levels.

**We may not have sufficient cash from operations after the establishment of cash reserves and payment of our expenses, including cost reimbursements to MPC and its affiliates, to enable us to pay the minimum quarterly distribution to our unitholders.**

We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution to our unitholders. The amount of cash we can distribute on our common units depends principally on the amount of cash we generate from our operations, which may fluctuate from quarter to quarter based on, among other things:

- the fees and tariff rates we charge and the margins we realize for our services and sales;
- the prices of, level of production of and demand for oil, natural gas, NGLs and refined products;
- the volumes of natural gas, crude oil, NGLs and refined products we gather, process, store, transport and fractionate;
- the level of our operating costs including repairs and maintenance;
- the relative prices of NGLs and crude oil, which impact the effectiveness of our hedging program; and
- prevailing economic conditions.

In addition, the actual amount of cash available for distribution may depend on other factors, some of which are beyond our control, including:

- the amount of our operating expenses and general and administrative expenses, including cost reimbursements to MPC in respect of those expenses;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions in our joint venture agreements, revolving credit facility or other agreements governing our debt;
- the level and timing of capital expenditures we make, including capital expenditures incurred in connection with our enhancement projects;

- the cost of acquisitions, if any; and
- the amount of cash reserves established by our general partner in its discretion.

In an effort to fund a greater portion of our organic growth with retained cash, the amount of cash reserves established by our general partner may increase in the future, which in turn may further reduce the amount of cash available for distribution.

Our inability, or limited ability, to control certain aspects of management of joint venture legal entities in which we have a partial ownership interest may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities where we have a noncontrolling ownership interest, or for entities that we operate but in which the noncontrolling interest owners have participative rights, we will be unable to control ongoing operational or other decisions, including the incurrence of capital expenditures that we may be required to fund, the incurrence of debt, or the pursuit of certain projects that we may want to pursue. Certain of our joint venture partners have the option to not make or may otherwise cease making, capital contributions, so we may be required to fully fund capital or operating expenditures for the joint venture. For joint ventures we operate, we may not receive adequate reimbursement for all of the expenditures we incur to operate the joint venture. In addition, we may be unable to control the amount of cash we receive from the operation of these entities, which could adversely affect our ability to pay the minimum quarterly distribution to our unitholders.

Furthermore, the amount of cash we have available for distribution depends primarily on our cash flow and not solely on profitability, which is affected by non-cash items. As a result, we may make distributions during periods when we record net losses and may not make distributions during periods when we record net income.

**We may not always be able to accurately estimate hydrocarbon reserves and expected production volumes; therefore, volumes we service in the future could be less than we anticipate.**

We work closely with our producer customers in an effort to understand hydrocarbon reserves and expected production volumes. We periodically review or have outside consultants review hydrocarbon reserve information and expected production data that is publicly available or that is provided to us by our producer customers. However, we may not be able to accurately estimate hydrocarbon reserves and production volumes expected to be delivered to us for a variety of reasons, including the unavailability of sufficiently detailed information and unanticipated changes in producers' expected drilling schedules. Significant declines in oil, natural gas or NGL prices could also cause producers to curtail or limit drilling operations, which may result in the volumes delivered to us being less than anticipated. Accordingly, we may not have accurate estimates of total reserves serviced by our assets, the anticipated life of such reserves or the expected volumes to be produced from those reserves. In such event, if we are unable to secure additional sources, then the volumes that we gather or process in the future could be less than anticipated. A decline in such volumes could have a material adverse effect on our results of operations and financial condition.

**Our expansion of existing assets and the construction of new assets, if completed, may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks that could adversely impact our business, financial condition, results of operations and cash flows.**

One of the ways we intend to grow our business is through the construction of, or additions to, our existing gathering, transportation, treating, processing, storage and fractionation facilities, which requires the expenditure of significant amounts of capital which may exceed our expectations. Construction involves many factors beyond our control including delays caused by third-party landowners, unavailability of materials, labor disruptions, environmental constraints, financing, accidents, weather and other factors. Additionally, we are subject to numerous regulatory, environmental, political, legal and inflationary uncertainties, including societal sentiment regarding the development and use of carbon-based fuels, political pressures and the influence of environmental or other special interest groups, as well as stringent, lengthy and occasionally unreasonable or impractical

federal, state and local permitting, zoning, consent, or authorizations requirements, or new laws, regulations, requirements or enforcement actions, which may cause us to incur additional capital expenditures, delay, interfere with or impair our construction activities, including by requiring the redesign of facilities, the acquisition of additional equipment, and relocations or rerouting of facilities, subject us to additional expenses or penalties and adversely affect our operations and cash flows available for distribution to unitholders. If we undertake these projects, we may not be able to complete them on schedule, or at all, or at the budgeted cost. We also may be required to incur additional costs and expenses in connection with the design and installation of our facilities due to their location and the surrounding terrain. We may be required to install additional facilities, incur additional capital and operating expenditures, or experience interruptions in or impairments of our operations to the extent that the facilities are not designed or installed correctly. For example, certain of our processing, fractionation and pipeline facilities are located in mountainous areas such as our Utica, Marcellus and southern Appalachian operations, which may require specially designed foundations, retaining walls and other structures or facilities. If such foundations, retaining walls or other facilities are not designed or installed correctly, do not perform as intended or fail, we may be required to incur significant capital expenditures to correct or repair the deficiencies, or may incur significant damage to or loss of facilities, and our operations may be interrupted as a result of deficiencies or failures. In addition, such deficiencies may cause damages to the surrounding environment, including slope failures, stream impacts and other natural resource damages, and we may as a result also be subject to increased operating expenses or environmental penalties and fines. In addition, certain agreements with our customers contain substantial financial penalties and/or give the producer the right to repurchase certain assets and terminate their contracts with us if construction deadlines are not achieved. Any such penalty or contract termination could have a material adverse effect on our income from operations and cash available for distribution. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues until after completion of the project, if at all.

Furthermore, we may have only limited oil, natural gas, NGL or refined product supplies committed to these facilities prior to their construction. We may construct facilities to capture anticipated future growth in production or satisfy anticipated market demand which does not materialize, the facilities may not operate as planned or may not be used at all. In order to attract additional oil, natural gas, NGL or refined product supplies from a customer, we may be required to order equipment and facilities, obtain rights of way or other land rights or otherwise commence construction activities for facilities that will be required to serve such customer's additional supplies prior to executing agreements with the customer. If such agreements are not executed, we may be unable to recover such costs and expenses. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough oil, natural gas, NGLs or refined products to achieve our expected investment return or result in immediate revenue increases, which could adversely affect our operations and cash available for distribution. Alternatively, oil, natural gas, NGL or refined product supplies committed to facilities under construction may be delivered prior to completion of such facilities, or we may otherwise have unexpected increase in volumes that could adversely affect our ability to expand our facilities. In such event, we may be required to temporarily utilize third-party facilities for such oil, natural gas, NGLs or refined products, which may increase our operating costs and reduce our cash available for distribution.

Other ways we may grow our business is through the construction of new pipelines or the expansion of existing ones. The construction of a new pipeline or the expansion of an existing pipeline, by adding horsepower or pump stations or by adding a second pipeline along an existing pipeline, involves numerous regulatory, environmental, political, and legal uncertainties, most of which are beyond our control. The approval process for storage and transportation projects has become increasingly challenging, due in part to state and local concerns related to pipelines and negative public perception regarding the oil and gas industry. These projects may not be completed on schedule (or at all) or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur

over an extended period of time and we will not receive any material increases in revenues until after completion of the project.

**Due to capacity, market and other constraints relating to the growth of our business, we may experience difficulties in the execution of our business plan, which may increase our costs and reduce our revenues and cash available for distribution.**

The successful execution of our business strategy is impacted by a variety of factors, including our ability to grow our business and satisfy our customers' requirements for gathering, processing, fractionation, marketing, transportation and storage services. Our ability to grow our business and satisfy our customers' requirements may be adversely affected by a variety of factors, including the following:

- more stringent permitting and other regulatory requirements;
- a limited supply of qualified fabrication and construction contractors, which could delay or increase the cost of the construction and installation of our facilities or increase the cost of operating our existing facilities;
- unexpected increases in the volume of oil, natural gas, NGLs and refined products being delivered to our facilities, which could adversely affect our ability to expand our facilities in a manner that is consistent with our customers' production or delivery schedules;
- changes in, or inability to meet, downstream gas, NGL, crude oil or refined product pipeline quality specifications, which could reduce the volumes of gas, NGLs, crude oil and refined products that we receive;
- scheduled maintenance, unexpected outages or downtime at our facilities or at upstream or downstream third-party facilities, which could reduce the volumes of oil, gas, NGLs and refined products that we receive; and
- market and capacity constraints affecting downstream oil, natural gas, NGL and refined products facilities, including limited gas and NGL capacity downstream of our facilities, limited railcar and NGL pipeline facilities and reduced demand or limited markets for certain NGL or refined products, which could reduce the volumes of oil, gas, NGLs and refined products that we receive and adversely affect the pricing received for NGLs.

If we are unable to successfully execute our business strategy, then our operating and capital expenditures may materially increase and our revenues and cash available for distribution may be adversely affected.

**We engage in commodity derivative activities to mitigate the impact of commodity price volatility on our cash flows, but these activities may reduce our earnings, profitability and cash flows. In addition, we may not accurately predict future commodity price fluctuations, our risk management activities may impair our ability to benefit from price increases, and additional regulation of commodity derivative activities could adversely impact our ability to manage these risks.**

Our operations expose us to fluctuations in commodity prices. We utilize derivative financial instruments related to the future price of crude oil, natural gas and certain NGLs with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices.

The extent of our commodity price exposure is related largely to our contract mix and the effectiveness and scope of our derivative activities. We have a policy to enter into derivative transactions related to only a portion of the volume of our expected production or fuel requirements that are subject to commodity price volatility and, as a result, we expect to continue to have some direct commodity price exposure. Our actual future production or fuel requirements may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the amount that is subject to our derivative

financial instruments, we might be forced to settle all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which could result in a substantial diminution of our liquidity. Alternatively, we may seek to amend the terms of our derivative financial instruments, including the extension of the settlement date of such instruments. Additionally, because we may use derivative financial instruments relating to the future price of crude oil to mitigate our exposure to NGL price risk, the volatility of our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. As a result of these factors, our risk management activities may not be as effective as we intend in reducing the downside volatility of our cash flows and, in certain circumstances, may actually increase the volatility of our cash flows. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect and our risk management policies and procedures are not properly followed. For further information about our risk management policies and procedures, please read Item 8. Financial Statements and Supplementary Data—Note 16.

To the extent that we do not manage the commodity price risk relating to a position that is subject to commodity price risk and commodity prices move adversely, we could suffer losses. Such losses could be substantial and could adversely affect our operations and cash flows available for distribution. In addition, managing the commodity risk may actually reduce our opportunity to benefit from increases in the market or spot prices.

As a result of the Dodd-Frank Act, over-the-counter derivatives markets and entities are subject to regulation by the Commodities Futures Trading Commission (the “CFTC”), the SEC and other regulators. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions that are or become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we believe that we qualify for the end-user exception to the mandatory clearing requirements for swaps to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants may change the cost and availability of the swaps that we use for hedging. Additional mandatory clearing requirements could be imposed that may impair our ability to maintain over-the-counter hedging positions or require us to post collateral. The Dodd-Frank Act and its implementing regulations, including those not yet finalized, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, increase the administrative burden and regulatory risk associated with entering into certain derivative contracts, and increase our exposure to less credit-worthy counterparties. As a result, if we reduce our use of derivatives, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on our income from operations and cash flows available for distribution.

**Due to an increased domestic supply of NGLs, we may be required to find alternative NGL market outlets and to rely more heavily on the export of NGLs, which may increase our operating costs or reduce the price received for NGLs and thereby reduce our cash available for distribution.**

Due to increased production of natural gas, particularly in shale plays, there is an increased domestic supply of NGLs, which is currently outpacing, and could continue to outpace, domestic demand. As a result, we and our producer customers may need to continue to find alternate NGL market outlets and to rely more heavily on the export of NGLs. Our ability to find alternative NGL market outlets is dependent upon a variety of factors, including the construction and installation of additional NGL transportation infrastructure necessary to transport NGLs to other markets. In order to obtain committed transportation capacity, it may be necessary to make significant minimum volume commitments, with take or pay payments or deficiency fees if the minimum volume is not delivered. In other instances, we may enter into long-term sales arrangements, and we may incur shortfall or deficiency fees or be subject to other liabilities, including breach of contract claims, if we do not deliver the contracted quantity. We market NGLs on behalf of various of our producer customers, and as a result, we may

make such commitments on behalf of those producer customers. We expect to be able to pass such commitments through to our producer customers, but if we were unable to do so, our operating costs may increase significantly, which could have a material adverse effect on our results of operations and our ability to make cash distributions. Certain of our producer customers have elected, or may from time to time in the future elect, to take in kind and market their NGLs directly, which may also impact our ability to meet any obligations we may have to deliver contracted quantities of NGLs or other commitments. Similarly, our ability to export NGLs on a competitive basis is impacted by various factors, including:

- availability of sufficient railcar, tanker and terminalling facility capacity;
- currency fluctuations;
- compliance with additional governmental regulations and maritime requirements, including U.S. export controls and foreign laws, sanctions regulations and the Foreign Corrupt Practices Act;
- risks of loss resulting from non-payment or non-performance by international purchasers; and
- political and economic disturbances in the countries to which NGLs are being exported.

The above factors could increase our operating costs or adversely affect the price that we and our producer customers receive for NGLs, which in turn may have a material adverse effect on our volumes, revenues, income and cash available for distribution.

**We depend on third parties for the oil, natural gas and refined products we gather, transport and store, the natural gas and refinery off-gas we process, and the NGLs we fractionate and stabilize at our facilities, and a reduction in these quantities could reduce our revenues and cash flow.**

Although we obtain our supply of oil, natural gas, refinery off-gas, NGLs and refined products from numerous third-party producers and suppliers, a significant portion comes from a limited number of key producers/suppliers, who are usually under no obligation to deliver a specific volume to our facilities. If these key suppliers, or a significant number of other producers, were to decrease the supply of oil, natural gas, refinery off-gas, NGLs or refined products to our systems and facilities for any reason, we could experience difficulty in replacing those lost volumes. In some cases, the producers or suppliers are responsible for gathering or delivering oil, natural gas, refinery off-gas, NGLs or refined products to our facilities or we rely on other third parties to deliver volumes to us on behalf of the producers or suppliers. If such producers, suppliers or other third parties are unable, or otherwise fail to, deliver the volumes to our facilities, or if our agreements with any of these third parties terminate or expire such that our facilities are no longer connected to their gathering or transportation systems or the third parties modify the flow of natural gas, refinery off-gas or NGLs on those systems away from our facilities, the throughput on and utilization of our facilities may be reduced, or we may be required to incur significant capital expenditures to construct and install gathering pipelines or other facilities to be able to receive such volumes. Because our operating costs are primarily fixed, a reduction in the volumes delivered to us would result not only in a reduction of revenues, but also a decline in net income and cash flow.

**We may not be able to retain existing customers, or acquire new customers, which would reduce our revenues and limit our future profitability.**

A significant portion of our business comes from a limited number of key customers. The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other gatherers, processors, pipelines and fractionators, and the price of, and demand for, natural gas, NGLs, crude oil and refined products in the markets we serve. Our competitors include large oil, natural gas, refining and petrochemical companies, some of which have greater financial resources, more numerous or greater capacity pipelines, processing and other facilities, greater access to natural gas, crude oil and NGL supplies than we do or other synergies with existing or new customers that we cannot provide. Our competitors may also include our joint venture partners, who in some

cases are permitted to compete with us and may have a competitive advantage due to their familiarity with our business arising from our joint venture arrangements, as well as third parties on whom we rely to deliver natural gas, NGLs, crude oil and refined products to our facilities, who may have a competitive advantage due to their ability to modify the flow of natural gas, NGLs, crude oil and refined products on their systems away from our facilities. Additionally, our customers that gather gas through facilities that are not otherwise dedicated to us may develop their own processing and fractionation facilities in lieu of using our services.

As a consequence of the increase in competition in the industry, and the volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternative fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could affect our profitability.

**The fees charged to third parties under our gathering, processing, transmission, transportation, fractionation, stabilization and storage agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances.**

Our costs may increase at a rate greater than the fees we charge to third parties. Furthermore, third parties may not renew their contracts with us. Additionally, some third parties' obligations under their agreements with us may be permanently or temporarily reduced due to certain events, some of which are beyond our control, including force majeure events wherein the supply of natural gas, NGLs, crude oil or refined products are curtailed or cut-off due to events outside our control, and in some cases, certain of those agreements may be terminated in their entirety if the duration of such events exceeds a specified period of time. If the escalation of fees is insufficient to cover increased costs, or if third parties do not renew or extend their contracts with us, or if third parties suspend or terminate their contracts with us, our financial results would suffer.

**We are exposed to the credit risks of our key customers and derivative counterparties, and any material non-payment or non-performance by our key customers or derivative counterparties could reduce our ability to make distributions to our unitholders.**

We are subject to risks of loss resulting from non-payment or non-performance by our customers, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. This risk is further heightened during sustained periods of declines of natural gas, NGL and oil prices. With respect to our producer customers who have made acreage dedications to us, we may be exposed to additional risks to the extent that those customers become bankrupt and the acreage dedications are challenged and not upheld in bankruptcy. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any such material non-payment or non-performance could reduce our ability to make distributions to our unitholders.

**Any strategic acquisitions are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.**

In addition to organic growth, a component of our business strategy can include the expansion of our operations through strategic acquisitions. Any acquisitions involve potential risks, including, amongst others:

- the validity of our assumptions about revenues, capital expenditures and operating costs of the acquired business or assets, as well as assumptions about achieving synergies with our existing business;



- the validity of our assessment of environmental and other liabilities, including legacy liabilities;
- the costs associated with additional debt or equity capital, which may result in a significant increase in our interest expense and financial leverage resulting from any additional debt incurred to finance such acquisitions, or the issuance of additional common units or preferred units on which we will make distributions, either of which could offset the expected accretion to our unitholders from such acquisition and could be exacerbated by volatility in the equity or debt capital markets;
- a failure to realize anticipated benefits, such as increased available cash per unit, enhanced competitive position or new customer relationships;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges; and
- the risk that our existing financial controls, information systems, management resources and human resources will need to grow to support future growth and we may not be able to react timely.

In addition, if we are unable to make accretive strategic acquisitions from MPC or third parties that increase the cash generated from operations per unit, whether due to an inability to identify attractive acquisition candidates, to negotiate acceptable purchase contracts, or to obtain financing for these acquisitions on economically acceptable terms, then our ability to successfully implement our business strategy may be impaired.

**If we are unable to timely and successfully integrate our future acquisitions, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transactions.**

Our future growth may depend in part on our ability to integrate our future acquisitions. We cannot guarantee that we will successfully integrate the assets acquired in the dropdowns from MPC, or any other acquisitions into our existing operations, or that we will achieve the desired profitability and anticipated results from such acquisitions. Failure to achieve such planned results could adversely affect our operations and cash available for distribution.

Significant acquisitions present potential risks including:

- operating a significantly larger combined organization and integrating additional operations into ours;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition, if at all. Following an acquisition, we may discover previously unknown liabilities, including environmental liabilities, which could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with applicable law. Our capitalization and results of operation may also change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we may consider in determining the application of these funds and other resources.

**We are indemnified for liabilities arising from an ongoing remediation of property on which certain of our facilities are located and our results of operations and our ability to make distributions to our unitholders could be adversely affected if an indemnifying party fails to perform its indemnification obligations.**

The prior third-party owner or operator of our Kenova, Boldman, Cobb, Kermit and Majorsville facilities has been or is currently involved in investigatory or remedial activities with respect to the real property underlying those facilities pursuant to regulatory orders with the EPA and various state regulatory agencies. The third party or its successor in interest has agreed to retain sole liability and responsibility for, and to indemnify us against, any environmental liabilities associated with these regulatory orders or the real property underlying these facilities to the extent such liabilities arose prior to the effective date of the agreements pursuant to which such properties were acquired or leased and to the extent not contributed to by us. In addition, the previous owner and/or operator of certain facilities on the real property on which our rail facility is constructed near Houston, Pennsylvania has been or is currently involved in investigatory or remedial activities related to AMD with respect to that real property. The third party has accepted liability and responsibility for, and has agreed to indemnify us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations. MPC has also agreed to indemnify us for certain environmental liabilities related to assets contributed to us by MPC in our Initial Offering or sold to us subsequently. Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected if in the future any of these third parties fail to perform their indemnification obligations. In addition, from time to time, we have acquired, and may acquire in the future, facilities from third parties which previously have been or currently are the subject of investigatory, remedial or monitoring activities relating to environmental matters. In some cases, we may receive indemnification from the prior owner or operator for some or all of such liabilities, and in other cases we may accept some or all of such liabilities. There is no assurance that any such third parties will perform any such indemnification obligations, or that the obligations and liabilities that we may accept in connection with any such acquisition will not be larger than anticipated, and in such event, our results of operations and cash available for distribution could be adversely affected.

**If foreign investment in us or our general partner exceeds certain levels, we could be prohibited from operating inland river vessels, which could materially and adversely affect our business, financial condition, results of operations and cash flows.**

The Shipping Act of 1916 and Merchant Marine Act of 1920, which we refer to collectively as the Maritime Laws, generally require that vessels engaged in U.S. coastwise trade be owned by U.S. citizens. Among other requirements to establish citizenship, entities that own such vessels must be owned at least 75 percent by U.S. citizens. If we fail to maintain compliance with the Maritime Laws, we would be prohibited from operating vessels in the U.S. inland waters. Such a prohibition could materially and adversely affect our business, financial condition, results of operations and cash flows.

### **Risks Relating to our Industry**

**Certain of our pipelines may be subject to federal or state rate and service regulation, and the imposition and/or cost of compliance with such regulation could adversely affect our operations and cash flows available for distribution to our unitholders.**

Some of our natural gas pipelines, and various of our crude oil, NGL, and refined product pipelines are, or may in the future be, subject to siting, public necessity and/or service regulations by FERC and/or various state or other regulatory bodies, depending upon jurisdiction. FERC generally regulates the transportation of natural gas, NGLs, crude oil and refined products in interstate commerce and FERC's regulatory authority includes: facilities construction, acquisition, extension or abandonment of services or facilities (for natural gas pipelines only); rates; operations; accounts and records; and depreciation and amortization policies. FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. FERC also may conduct audits of these facilities, and if FERC determines that we are not in

compliance with our tariff or applicable regulations, we may incur additional costs, expenses or penalties. For certain natural gas pipelines and certain NGL, crude oil and refined product common carrier pipelines, we have FERC tariffs on file and we may have additional pipelines in the future that may be subject to these requirements. We also own and are constructing pipelines, including pipelines that carry NGLs between our processing and fractionation facilities, that we believe are either not subject to FERC's jurisdiction or would otherwise meet the qualifications for a waiver from many or all of FERC's requirements. However, we cannot provide assurance that FERC will not at some point find that some or all of these pipelines are subject to FERC's requirements and/or are otherwise not exempt from certain requirements. Such a finding could subject us to potentially burdensome and expensive operational, reporting and other requirements as well as fines, penalties or other sanctions.

Most of our natural gas and NGL pipelines are generally not subject to regulation by FERC. The NGA specifically exempts natural gas gathering systems from FERC's jurisdiction. Yet, such operations may still be subject to regulation by various state agencies. The applicable statutes and regulations generally require that our rates and terms and conditions of service provide no more than a fair return on the aggregate value of the facilities used to render services and that we offer service to our shippers on a not unduly discriminatory basis. We cannot assure unitholders that FERC will not at some point determine that some or all of such pipelines are within its jurisdiction, and regulate such services, which could limit the rates that we may charge, increase our costs of operation, and subject us to fines, penalties or other sanctions. FERC rate cases can involve complex and expensive proceedings. For more information regarding regulatory matters that could affect our business, please read Item 1. Business—Regulatory Matters as set forth in this Annual Report on Form 10-K.

**Some of our natural gas and NGL pipelines, and various of our crude oil and refined product pipelines, are subject to FERC's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.**

A number of our pipelines provide interstate service that is subject to regulation by FERC. FERC prescribes rate methodologies for developing regulated tariff rates for these natural gas, interstate oil and products pipelines. FERC's regulated tariff may not allow us to recover all of our costs of providing services. Changes in FERC's approved rate methodologies, or challenges to our application of an approved methodology, could also adversely affect our rates. Additionally, shippers may protest (and FERC may investigate) the lawfulness of tariff rates. FERC can require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful and prescribe new rates prospectively.

MPC has agreed not to challenge, or to cause others to challenge or assist others in challenging, our tariff rates in effect during the term of our transportation services agreements with MPC. However, this agreement does not prevent other shippers or interested persons from challenging our tariff rates or proration rules; nor does it prevent regulators from reviewing our rates and tariffs on their own initiative. At the end of the term of each of our transportation services agreements with MPC, if the agreement is not renewed, MPC will be free to challenge, or to cause other parties to challenge or assist others in challenging, our tariffs in effect at that time.

Action by FERC could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition and results of operations.

**If we are unable to obtain new rights-of-way or other property rights, or the cost of renewing existing rights-of-way or property rights increases, then we may be unable to fully execute our growth strategy, which may adversely affect our operations and cash flows available for distribution to unitholders.**

The construction of additions to, or expansions of, our facilities may require us to obtain new rights-of-way or other property rights prior to constructing new plants, pipelines and other transportation and storage facilities. We may be unable to obtain such rights-of-way or other property rights to connect new natural gas supplies to our existing gathering lines, to connect our existing or future facilities to new natural gas, NGL, crude oil or

refined product markets, or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new or renew existing rights-of-way or other property rights, including the renewal of leases for land on which our processing facilities are located. If the cost of obtaining new or renewing existing rights-of-way or other property rights increases, it may adversely affect our operations and cash flows available for distribution to unitholders. If we are unable to renew a lease or other land rights for land on which any of our processing or other facilities are located, we may be required to remove our facilities from that site, which could require us to incur significant costs and expenses, disrupt our operations, and adversely affect our cash available for distribution.

**Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make distributions at our intended levels.**

Our revolving credit facility and our loan agreement with MPC Investment have variable interest rates. Although interest rates have been low during the past several years, the United States Federal Reserve raised interest rates in 2015, 2016 and 2017. As a result, interest rates on our debt could be higher than current levels, causing our financing costs to increase accordingly. In addition, we may in the future refinance outstanding borrowings under our revolving credit facility with fixed-rate indebtedness. Interest rates payable on fixed-rate indebtedness typically are higher than the short-term variable interest rates that we pay on borrowings under our revolving credit facility. We also have other fixed-rate indebtedness that we may need or desire to refinance in the future prior to the applicable stated maturity. Furthermore, as with other yield-oriented securities, our unit price will be impacted by our cash distributions and the implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue equity or incur debt for acquisitions or other purposes and to make distributions at our intended levels.

**Our business is subject to laws and regulations with respect to environmental, occupational safety and health, nuisance, zoning, land use and other regulatory matters, and the violation of, or the cost of compliance with, such laws and regulations could adversely affect our operations and cash flows available for distribution to our unitholders.**

Numerous governmental agencies enforce federal, regional, state and local laws and regulations on a wide range of environmental, occupational safety and health, nuisance, zoning, land use, endangered species and other regulatory matters. We could be adversely affected by increased costs due to stricter pollution-control requirements or liabilities resulting from non-compliance with operating or other regulatory permits. Strict joint and several liability may be incurred without regard to fault, or the legality of the original conduct, under certain of the environmental laws for remediation of contaminated areas, including CERCLA, RCRA and analogous state laws. Private parties, including the owners of properties located near our storage, fractionation and processing facilities or through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. New, more stringent environmental laws, regulations and enforcement policies, the listing of additional species as endangered or threatened or the designation of new critical habitat for listed species, and new, amended or re-interpreted permitting requirements, policies and processes, might adversely affect our operations and activities, and existing laws, regulations and policies could be reinterpreted or modified to impose additional requirements, delays or constraints on our construction of facilities or on our operations, increase our operating costs, or require our facilities to be aggregated into one air emissions permit or permit application. Federal, state and local agencies also could impose additional health and safety requirements, any of which could increase our operating costs. Local governments may adopt more stringent local permitting and zoning ordinances that impose additional time, place and manner restrictions, delays or constraints on our activities to construct and operate our facilities, require the relocation of our facilities, prevent or restrict the expansion of our facilities, or increase our costs to construct and operate our facilities, including the construction of sound mitigation devices.

In addition, we face the risk of accidental releases or spills associated with our operations, which could result in material costs and liabilities, including those relating to claims for damages to property, natural resources and persons, environmental remediation and restoration costs and governmental fines and penalties. Our failure to comply with or alleged non-compliance with environmental or safety-related laws and regulations could result in administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and even injunctions that restrict or prohibit some or all of our operations. For more information regarding the environmental, safety and other regulatory matters that could affect our business, please read Item 1. Business—Regulatory Matters and Item 1. Business—Environmental Regulation, each as set forth in this Annual Report on Form 10-K.

**Climate change legislation or regulations restricting emissions of GHGs or methane could result in increased operating costs, reduced demand for our services and adversely affect the cash flows available for distribution to our unitholders.**

As a consequence to an EPA administrative conclusion that GHGs present an endangerment to public health and the environment, the EPA and some states have adopted or are considering regulations aimed at regulating GHG emissions from certain stationary sources that are potential sources of certain principal, or criteria, pollutant emissions. For example, on June 3, 2016, EPA finalized new regulations that set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities. The regulations were part of the prior Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. The EPA has proposed a delay of this rule so that the EPA can determine whether to revise or rescind the regulations. Additionally, this rule is currently being challenged in court by various affected states. In addition, Pennsylvania has issued a proposed general permit applicable to compressor stations that specifically recognizes an emissions limit for methane. Because the issue of climate change continues to receive scientific and political attention, there is also the potential for further legislation or regulation that could result in increased operating costs and/or reduced demand for the oil, natural gas, NGLs and products we gather, process, fractionate, store and transport.

To the extent that state or federal legislation is passed or regulations are imposed to reduce or regulate GHG emissions, we may experience delays in the construction and installation of new facilities due to more stringent permitting requirements, incur additional costs to reduce methane emissions associated with our operations or be required to aggregate the emissions from separate facilities for permitting purposes or to relocate one or more of our facilities due to more stringent emissions standards. If we incur additional costs to reduce methane emissions associated with our operations, it is possible that we may be able to pass through a portion of those costs to our producer customers to the extent permitted under our contractual arrangements. To the extent that we incur additional costs or delays, our cash available for distribution may be adversely affected.

Our producer customers or suppliers may also experience similar issues, which may adversely impact their drilling schedules and production volumes and reduce the volumes delivered to us. For more information regarding greenhouse gas and methane emission and regulation, please read Item 1. Business—Environmental Regulation—Climate Change.

We have mature systems in place to manage potential acute physical risks, such as floods and hurricane-force winds, and potential chronic physical risks, such as higher ocean levels. If any such events were to occur, they could have an adverse effect on our assets and operations. Specifically, where appropriate, we are hardening and modernizing assets against flood and wind damage and ensuring we have resiliency measures in place, such as storm-specific readiness plans. We have incurred and will continue to incur additional costs to protect our assets and operations from such physical risks and employ the evolving technologies and processes available to mitigate such risks. To the extent such severe weather events increase in frequency and severity, we may be required to modify operations and incur costs that could materially and adversely affect our business, financial condition, results of operations and cash flows.

**Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could delay or impede oil or gas production or result in reduced volumes available for us to gather, transport, store, process and fractionate.**

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing, transportation, storage and fractionation services with respect to natural gas, oil, NGLs and refined products produced by our customers as a result of such operations. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but several federal agencies have asserted regulatory authority over certain aspects of the process, including the EPA and BLM. In addition, Congress has from time to time considered legislation to provide for additional regulation of hydraulic fracturing. Also, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult to complete natural gas and oil wells in shale formations and increase our producers' costs of compliance. This could significantly reduce the volumes delivered to us, which could adversely impact our earnings, profitability and cash flows.

**We are subject to operating and litigation risks that may not be covered by insurance.**

Our industry is subject to numerous operating hazards and risks incidental to gathering, processing, transporting, fractionating and storing natural gas and NGLs and to transporting and storing crude oil and refined products. These include:

- damage to pipelines, plants, storage facilities, barges, related equipment and surrounding properties caused by floods, hurricanes and other natural disasters and acts of terrorism;
- inadvertent damage from vehicles and construction and farm equipment;
- leakage of crude oil, natural gas, NGLs, refined products and other hydrocarbons into the environment, including groundwater;
- fires and explosions; and
- other hazards and conditions, including those associated with various hazardous pollutant emissions, high-sulfur content, or sour gas, and proximity to businesses, homes, or other populated areas, that could also result in personal injury and loss of life, pollution and suspension of operations.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates or at all, and, even if we are able to obtain such insurance, we may not be able to recover amounts from the insurance carrier for events that we believe are covered. In addition, insurance carriers now require broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our operations and cash available for distribution.

**We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs, and the expansion of pipeline safety laws and regulations could require us to use more comprehensive and stringent safety controls and subject us to increased capital and operating costs.**

The DOT through the PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for gas transmission and hazardous liquids pipelines located where a leak or rupture could do the most harm. The regulations require the following of operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;

- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Over the past several years, PHMSA has published new regulations, and issued notices for additional proposed regulations, to expand pipeline safety requirements.

In addition, PHMSA and other state regulators have recently expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities to assess compliance with hazardous liquids pipeline safety requirements, which actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators. The adoption of these and other laws or regulations that apply more comprehensive or stringent safety standards to gas, NGL, crude oil and refined product lines or other facilities, or the expansion of regulatory inspections by PHMSA and other state regulators described above, could require us to install new or modified safety controls, pursue added capital projects, make modifications or operational changes, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased capital and operational costs or operational delays that could be significant and have a material adverse effect on our financial position or results of operations and ability to make distributions to our unitholders.

Some states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. These regulations have raised operating costs for the industry, and compliance with such laws and regulations may cause us to incur potentially material capital expenditures associated with the construction, maintenance, and upgrading of equipment and facilities.

**The United States inland waterway infrastructure is aging and planned and unplanned maintenance may adversely affect our operations.**

Maintenance of the United States inland waterway system is vital to our marine transportation operations. The system is composed of over 12,000 miles of commercially navigable waterway, supported by over 240 locks and dams designed to provide flood control, maintain pool levels of water in certain areas of the country and facilitate navigation on the inland river system. The United States inland waterway infrastructure is aging, with more than half of the locks over 50 years old. As a result, due to the age of the locks, planned and unplanned maintenance may create more frequent outages, resulting in delays and additional operating expenses. Part of the costs for new construction and major rehabilitation of locks and dams is funded by marine transportation companies through taxes and the other portion is funded by general federal tax revenues. Failure of the federal government to adequately fund infrastructure maintenance and improvements in the future would have a negative impact on our ability to deliver products to our customers on a timely basis. Furthermore, any additional user taxes that may be imposed in the future to fund infrastructure improvements would increase our operating expenses.

**Interruptions in operations at any of our facilities or those of our customers, including MPC's refining operations, may adversely affect our operations and cash flows available for distribution to our unitholders.**

Our operations depend upon the infrastructure that we have developed, including processing and fractionation plants, storage facilities, gathering and transportation facilities, various other means of transportation and marketing services. Any significant interruption at these facilities or pipelines, or our customers' operations, including MPC's refining operations, or in our ability to gather, transport or store natural gas, NGLs, crude oil or other refined products to or from these facilities or pipelines for any reason, or to market or transport the natural gas, crude oil, NGLs or refined products, would adversely affect our operations and cash flows available for

distribution to our unitholders. In some cases, these events may also adversely affect the pricing received for NGLs, and may reduce the volumes of oil, gas, NGLs and refined products that we receive. Operations at our or our customers' facilities, including MPC's refineries, could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events, including damages to pipelines and facilities, related equipment and surrounding properties caused by earthquakes, tornadoes, hurricanes, floods, fires, severe weather, explosions and other natural disasters;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of natural gas, NGLs, crude oil or refined products to our pipelines, barges, processing and fractionation plants and associated facilities;
- disruption in our supply of power, water and other resources necessary to operate our facilities;
- a marine accident or spill event could close a portion of the inland waterway system;
- damage to our facilities resulting from gas, crude oil, NGLs or refined products that do not comply with applicable specifications; and
- inadequate fractionation, transportation or storage capacity or market access to support production volumes, including lack of availability of rail cars, barges, trucks and pipeline capacity, or market constraints, including reduced demand or limited markets for certain NGL products.

Our NGL fractionation, storage and marketing operations in the Marcellus and Utica regions are integrated, and as a result, it is possible that an interruption of these operations may impact operations in the other regions, which may exacerbate the impacts of such interruption.

The construction and operation of certain of our facilities in our G&P segment may be impacted by surface or subsurface mining operations by one or more third parties, which could adversely impact our construction activities or cause subsidence or other damage to our facilities. In such event, our construction may be prevented or delayed, or the costs and time increased, or our operations at such facilities may be impaired or interrupted, and we may not be able to recover the costs incurred for delays or to relocate or repair our facilities, from such third parties.

In addition, our marine transportation business is subject to weather conditions on a daily basis. Adverse weather conditions such as high or low water on the inland waterway systems, fog and ice, tropical storms, hurricanes and tsunamis on both the inland waterway systems and throughout the United States coastal waters can impair the operating efficiencies of the marine fleet. Such adverse weather conditions can cause a delay, diversion or postponement of shipments of products and are beyond our control. In addition, adverse water and weather conditions can negatively affect a towing vessel's performance, tow size, loading drafts, fleet efficiency, place limitations on night passages and dictate horsepower requirements.

**Information technology systems used in our operations could become the target of industrial espionage or cyber-attack, the occurrence of which could materially and adversely affect our results of operations, financial condition and cash flows.**

Our business has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications for the gathering and processing of natural gas, the gathering, fractionation, transportation and marketing of NGLs, and the gathering, storage and transportation of crude oil and refined products. We are heavily dependent on our information technology systems and network infrastructure and maintain and rely upon certain critical information systems for the effective operation of our business. We rely on such systems to process, transmit and store electronic information, including financial records and personally identifiable information such as contractor, investor and payroll data, and to manage or support a variety of



business processes, including our supply chain, financial transactions, banking and numerous other processes and transactions. These information systems involve data network and telecommunications, Internet access and website functionality, and various computer hardware equipment and software applications, including those that are critical to the safe operation of our business. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our systems and networks, as well as those of our customers, vendors and counterparties, may become the target of cyber-attacks or information security breaches, which in turn could result in the unauthorized release and misuse of confidential or proprietary information as well as disrupt our operations, damage our facilities or those of third parties or cause spills or releases, any or all of which could have a material adverse effect on our revenues, increase our operating and capital costs, and reduce the amount of cash otherwise available for distribution. Additionally, as cyber incidents continue to evolve we may be required to incur additional costs to modify or enhance our systems or in order to try to prevent or remediate any such attacks. Our systems and infrastructure are subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cyber-attacks and other events. We also face various other cyber-security threats from criminal hackers, state-sponsored intrusion, industrial espionage and contractor malfeasance, including threats to gain unauthorized access to sensitive information or to render data or systems unusable. To protect against such attempts of unauthorized access or attack, we have implemented infrastructure protection technologies and disaster recovery plans and continuously provide awareness training around phishing, malware and other cyber-attacks to help ensure we are protected against cyber risks and security breaches. While we have invested significant amounts in the protection of our technology systems and maintain what we believe are adequate security controls over personally identifiable investor and contractor data, there can be no guarantee such plans, to the extent they are in place, will be effective. Certain vendors have access to sensitive information, including personally identifiable investor and contractor data and a breakdown of their technology systems or infrastructure as a result of a cyber-attack or otherwise could result in unauthorized disclosure of such information. Unauthorized disclosure of sensitive or personally identifiable information, including by cyber-attacks or other security breach, could cause loss of data, give rise to remediation or other expenses, expose us to liability under federal and state laws, reduce our customers' willingness to do business with us, disrupt the services we provide to customers and subject us to litigation and investigations, which could have an adverse effect on our reputation, business, financial condition, results of operations and cash flows available for distribution to our unitholders. In addition our applicable insurance may not compensate us adequately for losses that may occur. State and federal cyber-security legislation could also impose new requirements, which could increase our cost of doing business.

**Terrorist attacks aimed at our facilities or that impact our customers or the markets we serve could adversely affect our business.**

The U.S. government has issued warnings that energy assets in general, and the nation's pipeline and terminal infrastructure in particular, may be future targets of terrorist organizations. The threat of terrorist attacks has subjected our operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. Similarly, any future terrorist attacks that severely disrupt the markets we serve could materially and adversely affect our results of operations, financial position and cash flows.

**Risks Relating to the Business and Operations of MPC**

**MPC accounted for a large portion of our revenues in 2017 and will continue to do so on a go-forward basis. If MPC changes its business strategy, is unable to satisfy its obligations to us or significantly reduces the volumes transported through our facilities or stored at our storage assets, our revenues would decline and our financial condition, results of operations, cash flows, and ability to make distributions to our unitholders would be materially and adversely affected.**

For the year ended December 31, 2017, excluding revenues attributable to volumes shipped by MPC under joint tariffs with third parties that were treated as third-party revenues for accounting purposes, MPC accounted for

approximately 36 percent of our revenues and other income, including 92 percent of the revenues and other income within our L&S segment, and we believe MPC will continue to account for a large portion of our revenues on a go forward basis. As we expect to continue to derive a portion of our revenues from MPC for the foreseeable future, any event that materially and adversely affects MPC's financial condition, results of operations or cash flows may adversely affect our ability to sustain or increase distributions to our unitholders. Accordingly, we are indirectly subject to the operational and business decisions and risks of MPC, the most significant of which include the following:

- the timing and extent of changes in commodity prices and demand for MPC's products, and the availability and costs of crude oil and other refinery feedstocks;
- a material decrease in the refining margins at MPC's refineries;
- the risk of contract cancellation, non-renewal or failure to perform by MPC's customers, and MPC's inability to replace such contracts and/or customers;
- disruptions due to equipment interruption or failure at MPC's facilities or at third-party facilities on which MPC's business is dependent;
- any decision by MPC to temporarily or permanently alter, curtail or shut down operations at one or more of its refineries or other facilities and reduce or terminate its obligations under our transportation and storage services agreements;
- changes to the routing of volumes shipped by MPC on our crude oil and product pipelines or the ability of MPC to utilize third-party pipeline connections to access our pipelines;
- MPC's ability to remain in compliance with the terms of its outstanding indebtedness;
- changes in the cost or availability of third-party pipelines, terminals and other means of delivering and transporting crude oil, feedstocks, refined products and other hydrocarbon-based products;
- state and federal environmental, economic, health and safety, energy and other policies and regulations, and any changes in those policies and regulations;
- environmental incidents and violations and related remediation costs, fines and other liabilities;
- operational hazards and other incidents at MPC's refineries and other facilities, such as explosions and fires, that result in temporary or permanent shut downs of those refineries and facilities;
- changes in crude oil and product inventory levels and carrying costs; and
- disruptions due to hurricanes, tornadoes or other forces of nature.

We have no control over MPC's business decisions and operations, and MPC may elect to pursue a business strategy that does not favor us and our business. In addition, significant stockholders of MPC may attempt to affect changes at MPC or acquire control of the company, which could impact the pursuit of MPC's business strategies. Campaigns by stockholders to affect changes at publicly traded companies are sometimes led by investors seeking to increase short-term stockholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. As a result, stockholder campaigns at MPC could directly or indirectly adversely affect our results of operations and financial condition and our ability to sustain or increase distributions to our unitholders.

**MPC may suspend, reduce or terminate its obligations under our transportation and storage services agreements in some circumstances, which would have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.**

Our transportation and storage services agreements with MPC include provisions that permit MPC to suspend, reduce or terminate its obligations under the applicable agreement if certain events occur. These events include a

material breach of the applicable agreement by us, MPC being prevented from transporting its full minimum volume commitment because of capacity constraints on our pipelines, certain force majeure events that would prevent us from performing some or all of the required services under the applicable agreement and MPC's determination to suspend refining operations at one of its refineries. MPC has the discretion to make such decisions notwithstanding the fact that they may significantly and adversely affect us. These actions could result in a suspension, reduction or termination of MPC's obligations under one or more transportation and storage services agreements.

Any such reduction, suspension or termination of MPC's obligations would have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

**If MPC satisfies only its minimum obligations under, or if we are unable to renew or extend, the transportation and storage services agreements we have with MPC, or if MPC elects to use credits upon the expiration or termination of a transportation services agreement, our cash available for distribution will be materially and adversely affected.**

MPC is not obligated to use our services with respect to volumes of crude oil or products in excess of the minimum volume commitments under the transportation services agreements with us. Our cash available for distribution will be materially and adversely affected to the extent that we do not transport volumes in excess of the minimum volume commitments under our transportation services agreements or if MPC's obligations under our transportation and storage services agreements are suspended, reduced or terminated. In addition, the initial terms of MPC's obligations under those agreements range from three to 10 years. If MPC fails to use our assets and services after expiration of those agreements and we are unable to generate additional revenues from third parties, our ability to make distributions to unitholders may be materially and adversely affected.

In addition, under our transportation services agreements, MPC must pay us a deficiency payment if it fails to transport its minimum throughput commitment. MPC may then apply the amount of any such deficiency payments as a credit for volumes transported on the applicable pipeline in excess of its minimum volume commitment during the following four quarters or eight quarters under the terms of the applicable transportation services agreement. Upon the expiration or termination of a transportation services agreement, MPC may use any remaining credits against any volumes shipped by MPC on the applicable pipeline for the succeeding four or eight quarters, as applicable, without regard to any minimum volume commitment that may have been in place during the term of the agreement. If that were to occur, we would not receive any cash payments for volumes shipped on the applicable pipeline until any such remaining credits were fully used or until the expiration of the applicable four or eight quarter period.

**MPC's level of indebtedness, the terms of its borrowings and its credit ratings could adversely affect our ability to grow our business and our ability to make distributions to our unitholders. Our ability to obtain credit in the future may also be adversely affected by MPC's credit rating.**

MPC must devote a portion of its cash flows from operating activities to service its indebtedness, and therefore, cash flows may not be available for use in pursuing its growth strategy. Furthermore, a higher level of indebtedness at MPC in the future increases the risk that it may default on its obligations to us under our transportation and storage services agreements. As of December 31, 2017, MPC had consolidated long-term indebtedness of approximately \$13 billion, of which \$7 billion was a direct obligation of MPC. The covenants contained in the agreements governing MPC's outstanding and future indebtedness may limit its ability to borrow additional funds for development and make certain investments and may directly or indirectly impact our operations in a similar manner.

Furthermore, if MPC were to default under certain of its debt obligations, there is a risk that MPC's creditors would attempt to assert claims against our assets during the litigation of their claims against MPC. The defense of any such claims could be costly and could materially impact our financial condition, even absent any adverse

determination. If these claims were successful, our ability to meet our obligations to our creditors, make distributions and finance our operations could be materially and adversely affected.

MPC's long-term credit ratings are currently investment grade. If these ratings are lowered in the future, the interest rate and fees MPC pays on its credit facilities may increase. Credit rating agencies will likely consider MPC's debt ratings when assigning ours because of MPC's ownership interest in us, the significant commercial relationships between MPC and us, and our reliance on MPC for a portion of our revenues. If one or more credit rating agencies were to downgrade the outstanding indebtedness of MPC, we could experience an increase in our borrowing costs or difficulty accessing the capital markets. Such a development could adversely affect our ability to grow our business and to make distributions to our unitholders.

### **Risks Relating to Tax Matters**

**Our tax treatment depends on our status as a partnership for federal income tax purposes as well as our not being subject to a material amount of entity level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.**

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this.

A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations, we believe that we are treated as a partnership rather than as a corporation for such purposes; however, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes. We have requested and received a favorable ruling from the IRS on the treatment of a portion of our "qualifying income." The IRS may adopt positions that differ from the ones we take. A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any IRS contest will reduce our cash available for distribution to unitholders.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 21 percent, and likely would pay state and local income tax at varying rates. Distributions to unitholders generally would be taxed again as corporate dividends, and no income, gains, losses, deductions, or credits would flow through to our unitholders. Treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units. Changes in current state law may subject us to additional entity-level taxation by individual states. Imposition of any such additional taxes on us will substantially reduce the cash available for distribution to unitholders.

Our Partnership Agreement provides that, if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

**If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution.**

The IRS has made no determination as to our status as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all the positions we take. A court may not agree with some or all of the positions

we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

**Our unitholders will be required to pay taxes on their share of income even if they do not receive any distributions from us.**

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no distributions from us. Our unitholders may not receive distributions from us equal to their share of our taxable income or even equal to the actual tax liability that result from that income.

**Tax gain or loss on the disposition of our common units could be more or less than expected.**

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in their common units, the amount, if any, of such prior excess distributions with respect to their units will, in effect, become taxable income to the unitholder if the common units are sold at a price greater than the unitholder's tax basis in those common units, even if the price the unitholder receives is less than the unitholder's original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, if a unitholder sells units, the unitholder may incur a tax liability in excess of the amount of cash received from the sale.

**Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.**

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Non-U.S. persons will also potentially have tax filings and payment obligations in additional jurisdictions. Tax-exempt entities and non-U.S. persons should consult their tax advisor before investing in our common units.

**We treat each purchaser of common units as having the same tax benefits without regard to the actual units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.**

To maintain the uniformity of the economic and tax characteristics of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

**Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.**

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various

jurisdictions in which we do business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently conduct business in approximately 17 states. Many of these states currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all U.S. federal, state and local tax returns.

**We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.**

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, or our allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

**A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.**

A unitholder who loans his common units to a "short seller" to cover a short sale of common units (i) may be considered as having disposed of the loaned common units, (ii) may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and (iii) may recognize gain or loss from such disposition.

Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

**The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.**

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time.

Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes or increase the amount of taxes payable by unitholders in publicly traded partnerships.

**We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.**

We prorate our items of income, gain, loss and deduction between existing unitholders and unitholders who purchase our units based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

**If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.**

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (or choose to do so) under all circumstances. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be reduced.

### **Risks Relating to Ownership of our Common Units**

**Our general partner and its affiliates, including MPC, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to our detriment and that of our unitholders. Additionally, we have no control over MPC's business decisions and operations, and MPC is under no obligation to adopt a business strategy that favors us.**

MPC owns our general partner and approximately 64 percent of our outstanding common units as of February 16, 2018. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of our partnership and our unitholders, the directors and officers of our general partner also have a duty to manage our general partner in a manner that is not adverse to the best interests of its owner, MPC.

Conflicts of interest may arise between MPC and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, the general partner may favor its own interests and the interests of its affiliates, including MPC, over the interests of our common unitholders, which may occur under our Partnership Agreement without being independently reviewed by the conflicts committee. These conflicts include, among others, the following situations:

- neither our Partnership Agreement nor any other agreement requires MPC to pursue a business strategy that favors us or utilizes our assets, which could involve decisions by MPC to increase or decrease refinery production, shut down or reconfigure a refinery, or pursue and grow particular markets. MPC's directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of MPC;

- MPC, as a significant customer, has an economic incentive to cause us to not seek higher tariff rates, even if such higher rates or fees would reflect rates and fees that could be obtained in arm's-length, third-party transactions;
- MPC may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;
- our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner will determine the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner will determine the amount and timing of many of our cash expenditures and whether a cash expenditure is classified as an expansion capital expenditure, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce our operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the amount of adjusted operating surplus generated in any given period;
- our general partner will determine which costs incurred by it are reimbursable by us and may cause us to pay it or its affiliates for any services rendered to us;
- our general partner may cause us to borrow funds in order to permit the payment of distributions;
- our Partnership Agreement permits us to classify up to \$60 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner;
- our Partnership Agreement does not restrict our general partner from entering into additional contractual arrangements with it or its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 85 percent of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including our transportation and storage services agreements with MPC; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Under the terms of our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors and owners. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.



**Our Partnership Agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.**

Our Partnership Agreement requires that we distribute all of our available cash to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance our growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the amount of cash available to distribute to our unitholders.

**Our Partnership Agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties and restricts the remedies available to unitholders for actions taken by our general partner.**

Our Partnership Agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing. Our general partner is entitled to consider only the interests and factors that it desires and is relieved of any duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or our limited partners.

Our Partnership Agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our Partnership Agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith and will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that our general partner will not be in breach of its obligations under our Partnership Agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is approved in accordance with, or otherwise meets the standards set forth in, our Partnership Agreement.

In connection with a transaction with an affiliate or a conflict of interest, our Partnership Agreement provides that any determination by our general partner must be made in good faith, and that our conflicts committee and the board of directors of our general partner are entitled to a presumption that they acted in good faith. 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. By purchasing a common unit, a unitholder is treated as having consented to the provisions in our Partnership Agreement, including the provisions discussed above.

**Unitholders have very limited voting rights and, even if they are dissatisfied, they have limited ability to remove our general partner without its consent.**

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by the members of our general partner, which are wholly-owned subsidiaries of MPC. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The vote of the holders of at least 66 2/3 percent of all outstanding common units voting together as a single class is required to remove our general partner. As of February 16, 2018, our general partner and its affiliates owned approximately 64 percent of the outstanding common units (excluding common units held by officers and directors of our general partner and MPC). As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Furthermore, unitholders' voting rights are further restricted by the Partnership Agreement provision providing that any units held by a person that owns 20 percent or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

**If unitholders are not both citizenship-eligible holders and rate-eligible holders, their common units may be subject to redemption.**

In order to avoid (1) any material adverse effect on the maximum applicable rates that can be charged to customers by our subsidiaries on assets that are subject to rate regulation by the FERC or analogous regulatory body, and (2) any substantial risk of cancellation or forfeiture of any property, including any governmental permit, endorsement or other authorization, in which we have an interest, we have adopted certain requirements regarding those investors who may own our common units. Citizenship eligible holders are individuals or entities whose nationality, citizenship or other related status does not create a substantial risk of cancellation or forfeiture of any property, including any governmental permit, endorsement or authorization, in which we have an interest, and will generally include individuals and entities who are U.S. citizens. Rate eligible holders are individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are subject to such taxation. If unitholders are not persons who meet the requirements to be citizenship eligible holders and rate eligible holders, they run the risk of having their units redeemed by us at the market price as of the date three days before the date the notice of redemption is mailed. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. In addition, if unitholders are not persons who meet the requirements to be citizenship eligible holders, they will not be entitled to voting rights.

**Cost reimbursements, which will be determined in our general partner's sole discretion, and fees due our general partner and its affiliates for services provided will be substantial and will reduce our cash available for distribution.**

Under our Partnership Agreement, we are required to reimburse our general partner and its affiliates for all costs and expenses that they incur on our behalf for managing and controlling our business and operations. Except to the extent specified under our omnibus agreement or our employee services agreements, our general partner determines the amount of these expenses. Under the terms of the omnibus agreement, we will be required to reimburse MPC for the provision of certain general and administrative services to us. Under the terms of our employee services agreements, we have agreed to reimburse MPC or its affiliates for the provision of certain operational and management services to us in support of our facilities. Our general partner and its affiliates also may provide us other services for which we will be charged fees as determined by our general partner. Payments to our general partner and its affiliates will be substantial and will reduce the amount of cash available for distribution to unitholders.

**The control of our general partner may be transferred to a third party without unitholder consent.**

There is no restriction in our Partnership Agreement on the ability of MPC to transfer its membership interest in our general partner to a third party. The new partners of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to control the decisions taken by the board of directors and officers.

**We may issue additional units without unitholder approval, which will dilute limited unitholder interests.**

At any time, we may issue an unlimited number of limited partner interests of any type, including limited partner interests that are convertible into our common units, without the approval of our unitholders and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such limited partner interests. Further, neither our Partnership Agreement nor our bank revolving credit facility prohibits the issuance of additional preferred units, or other equity securities that may effectively rank senior to our common units as to distributions or liquidations. The issuance by us of additional common units, preferred units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- it may be more difficult to maintain or increase our distributions to unitholders, and the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

**MPC may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.**

As of February 16, 2018, MPC held 504,701,934 common units. Additionally, we have agreed to provide MPC with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

**Affiliates of our general partner, including MPC, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.**

Neither our Partnership Agreement nor our omnibus agreement will prohibit MPC or any other affiliates of our general partner from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, MPC and other affiliates of our general partner may acquire, construct or dispose of additional

midstream assets in the future without any obligation to offer us the opportunity to purchase any of those assets. As a result, competition from MPC and other affiliates of our general partner could materially and adversely impact our results of operations and cash available for distribution to unitholders.

**Our general partner has a limited call right that may require unitholders to sell common units at an undesirable time or price.**

If at any time our general partner and its affiliates own more than 85 percent of our common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of such units.

**A unitholder's liability may not be limited if a court finds that unitholder action constitutes control of our business.**

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made non-recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some jurisdictions. A unitholder could be liable for our obligations as if they were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute "control" of our business.

**Unitholders may have to repay distributions that were wrongfully distributed to them.**

Under certain circumstances, unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for the obligations of the transferor to make contributions to the partnership that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from our Partnership Agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

**The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.**

We list our common units on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

**Item 1B. Unresolved Staff Comments**

None

## Item 2. Properties

### LOGISTICS AND STORAGE

#### Crude Oil Pipelines

The following table sets forth certain information regarding our crude oil pipelines, as of December 31, 2017.

Pipeline Name	Diameter (inches)	Length (miles)	Capacity (mbpd) <sup>(1)</sup>	Associated MPC Refineries
<b>Patoka to Lima and Canton crude pipelines</b>				
Patoka, IL to Lima, OH	20"/22"	302	267	Detroit, MI; Canton, OH
Lima OH, to Canton, OH	12"/16"	153	84	Canton, OH
Subtotal		455	351	
<b>Catlettsburg and Robinson crude pipelines</b>				
Patoka, IL to Robinson, IL	20"	78	245	Robinson, IL
Patoka, IL to Catlettsburg, KY	24"/20"	406	270	Catlettsburg, KY
Subtotal		484	515	
<b>Detroit crude pipelines</b>				
Samaria, MI to Detroit, MI	16"	44	117	Detroit, MI
Romulus, MI to Detroit, MI <sup>(2)</sup>	16"	17	80	Detroit, MI
Subtotal		61	197	
<b>Ozark crude pipeline</b>				
Cushing, OK to Wood River, IL	22"	433	230	All Midwest refineries
<b>Wood River to Patoka crude pipelines</b>				
Wood River, IL to Patoka, IL	22"	57	215	All Midwest refineries
Roxanna, IL to Patoka, IL <sup>(3)</sup>	12"	58	99	All Midwest refineries
Subtotal		115	314	
<b>St. James to Garyville crude pipeline</b>				
St. James, LA to Garyville, LA	30"	20	620	Garyville, LA
<b>Inactive pipelines</b>				
		45	N/A	
<b>Total</b>		1,613	2,227	

(1) Capacity shown is 100 percent of the capacity of these pipelines and based on physical barrels.

(2) Includes approximately 16 miles of pipeline leased from a third party.

(3) This pipeline is leased from a third party.

The following table sets forth certain information regarding crude oil pipelines in which we have a joint interest, as of December 31, 2017.

Pipeline Name	Diameter (inches)	Length (miles)	Ownership Interest
<b>Bakken Pipeline</b>			9.2%
Dakota Access Pipeline	30"	1,172	
Energy Transfer Crude Oil Company (ETCO) pipeline	30"	749	
Subtotal		<u>1,921</u>	
<b>Illinois Extension</b>	24"	168	35%
<b>LOOP</b>	48"	48	40.7%
<b>LOCAP</b>	48"	57	58.5%
<b>Total</b>		<u><u>2,194</u></u>	

Our crude oil pipeline and related assets are strategically positioned to support diverse and flexible crude oil supply options for MPC's Midwest refineries, which receive imported and domestic crude oil through a variety of sources. Imported and domestic crude oil is transported to supply hubs in Wood River and Patoka, Illinois from a variety of regions, including: Cushing, Oklahoma on the Ozark pipeline; Western Canada, Wyoming and North Dakota on the Keystone, Platte, Mustang and Enbridge pipelines; and the Gulf Coast on the Capline crude oil pipeline. Our major crude oil pipelines are connected to these supply hubs and transport crude oil to refineries owned by MPC and third parties.

## Product Pipelines

The following table sets forth certain information regarding our product pipelines as of December 31, 2017.

Pipeline Name	Diameter (inches)	Length (miles)	Capacity (mbpd) <sup>(1)</sup>	Associated MPC Refineries
<b>Louisiana products pipelines</b>				
Garyville, LA to Zachary, LA	20"	70	389	Garyville, LA
Zachary, LA to connecting pipelines <sup>(2)</sup>	36"	2	N/A	Garyville, LA
Subtotal		72	389	
<b>Texas products pipelines</b>				
Texas City, TX to Pasadena, TX	16"	40	215	Galveston Bay, TX
Pasadena, TX to connecting pipelines <sup>(2)</sup>	36"/30"	3	N/A	Galveston Bay, TX
Subtotal		43	215	
<b>Ohio products pipelines</b>				
Bellevue 4" Products	4"	3	5	N/A
Canton, OH to East Sparta, OH <sup>(2,3)</sup>	6"	17	73	Canton, OH
Columbus Locals	12"	1	N/A	N/A
Cornerstone Pipeline				
Cadiz, OH to East Sparta, OH	16"	50	198	Canton, OH
East Sparta, OH to Canton, OH	8"	8	40	Canton, OH
East Sparta, OH to Heath, OH	8"	81	47	Canton, OH
East Sparta, OH to Midland, PA	8"	62	32	Canton, OH
Heath, OH to Dayton, OH	6"	108	24	Catlettsburg, KY; Canton, OH
Heath, OH to Findlay, OH or Lima, OH	8"/12"	149	63	Catlettsburg, KY; Canton, OH
Kenova, WV to Columbus, OH	14"	150	68	Catlettsburg, KY
Lima Pump-Out <sup>(4)</sup>	12"	N/A	N/A	N/A
RIO	8"	251	24	N/A
Toledo, OH to Steubenville, OH	4"/6"	54	32	N/A
Subtotal		934	606	
<b>Illinois products pipelines</b>				
Robinson, IL to Lima, OH	10"	250	51	Robinson, IL
Robinson, IL to Louisville, KY	16"	129	82	Robinson, IL
Robinson, IL to Mt. Vernon, IN <sup>(5)</sup>	10"	79	77	Robinson, IL
Wood River, IL to Clermont, IN	10"	317	48	Robinson, IL
Wabash Pipeline				
West leg—Wood River, IL to Champaign, IL	12"	130	71	Robinson, IL
East leg—Robinson, IL to Champaign, IL	12"	86	99	Robinson, IL
Champaign, IL to Hammond, IN <sup>(6)</sup>	16"/12"	140	85	Robinson, IL
Subtotal		1,131	513	
<b>Michigan product pipelines</b>				
Detroit LPG—Woodhaven #1	4"	12	6	N/A
Detroit LPG—Woodhaven #2	4"	14	6	N/A
Subtotal		26	12	
<b>Kentucky products pipeline</b>				
Louisville, KY to Louisville International Airport	8"/6"	14	29	Robinson, IL
Louisville, KY to Lexington, KY <sup>(7)</sup>	8"	87	37	N/A
Subtotal		101	66	
<b>Inactive pipelines<sup>(8)</sup></b>				
		140	N/A	
<b>Total</b>		<b>2,447</b>	<b>1,801</b>	

- (1) Capacity shown is 100 percent of the capacity of these pipelines and based on physical barrels.
- (2) Consists of two separate approximately 8.5 mile pipelines.
- (3) This pipeline is bi-directional.
- (4) Capacity not shown, as the pipeline is designed to meet outgoing capacity for connecting third-party pipelines.
- (5) This pipeline is leased from a third party.
- (6) Capacity not shown for 16 miles on this pipeline due to complexities associated with bi-directional capability.
- (7) We own a 65 percent undivided joint interest in the Louisville, KY to Lexington, KY system.
- (8) Includes 77 miles of pipeline leased from a third party.

The following table sets forth certain information regarding a products pipeline in which we have a joint interest, as of December 31, 2017.

<u>Pipeline Name</u>	<u>Diameter (inches)</u>	<u>Length (miles)</u>	<u>Ownership Interest</u>
Explorer Pipeline	12"-28"	1,830	24.5%
<b>Total</b>		<u>1,830</u>	

Our product pipelines are strategically positioned to transport products from six of MPC's refineries to MPC's marketing operations, as well as those of third parties. These pipelines also supply feedstocks to MPC's Midwest refineries. These product pipelines are integrated with MPC's expansive network of refined product marketing terminals, which support MPC's integrated midstream business.

### Terminal Assets

The following table sets forth certain information regarding our owned and operated terminals as of December 31, 2017.

<u>Owned and Operated Terminals<sup>(1)</sup></u>	<u>Number of Terminals</u>	<u>Tank Shell Capacity (thousand barrels)</u>	<u>Number of Tanks</u>	<u>Number of Loading Lanes</u>
Alabama	2	443	16	4
Florida	4	3,422	65	22
Georgia	4	998	31	9
Illinois	4	1,275	34	14
Indiana	6	3,229	60	17
Kentucky	6	2,587	56	25
Louisiana	1	97	7	2
Michigan	8	2,440	73	26
North Carolina	4	1,509	34	13
Ohio	12	3,227	101	28
Pennsylvania	1	390	12	2
South Carolina	1	370	8	3
Tennessee	4	1,148	30	12
West Virginia	2	1,587	25	2
<b>Total</b>	<u>59</u>	<u>22,722</u>	<u>552</u>	<u>179</u>

- (1) MPLX Terminals owns and operates 59 terminals, operates one leased terminal and has partial ownership interest in two terminals, with a combined tank shell capacity of 1,067 mbbls.



## Marine Assets

The following table sets forth certain information regarding our marine assets as of December 31, 2017. The marine business currently has an associated transportation service agreement with MPC.

Marine Vessels	Number at December 31, 2017	Capacity (thousand barrels)	Associated MPC Refineries
Inland tank barges:			Catlettsburg, KY; Garyville, LA
Less than 25,000 barrels	62	942	
25,000 barrels and over	170	4,985	
Total	<u>232</u>	<u>5,927</u>	
Inland towboats:			Catlettsburg, KY; Garyville, LA
Less than 2,000 horsepower	2		
2,000 horsepower and over	16		
Total	<u>18</u>		

Our fleet of boats and barges transport light products, heavy oils, crude oil, renewable fuels, chemicals and feedstocks to and from refineries and terminals owned by MPC in the Midwest and U.S. Gulf Coast regions. The MRF is a full-service marine shipyard located on the Ohio River, adjacent to MPC's Catlettsburg, Kentucky refinery. The MRF is responsible for the preventive routine and unplanned maintenance of towing vessels, barges and local terminal facilities.

## Other L&S Assets

The following table sets forth certain information regarding our other midstream assets as of December 31, 2017, each of which currently has an associated transportation services agreement or storage services agreement with MPC.

Asset Name	Capacity <sup>(1)</sup>	Associated MPC Refineries
LOOP <sup>(2)</sup>	N/A	N/A
Wood River Barge Dock	78 mbpd	Garyville, LA
Tank Farms <sup>(3)</sup>	18,642 mbbls	N/A
Caverns	2,755 mbbls	N/A

<sup>(1)</sup> Capacity for Tank Farms and Caverns is shown as 100 percent of the available storage capacity. Capacity for the Wood River Barge Dock is shown as 100 percent of the throughput capacity.

<sup>(2)</sup> We have a 40.7 percent interest in LOOP, which includes a deepwater oil port and crude oil storage.

<sup>(3)</sup> We own and operate 15 tank farms, and operate two leased tank farms.

## GATHERING AND PROCESSING

The following tables set forth certain information relating to our gas processing facilities, fractionation facilities, natural gas gathering systems, NGL pipelines, natural gas pipeline and crude oil and refined product pipelines as of and for the year ended December 31, 2017. All throughputs and utilizations included are weighted-averages for days in operation.

## Gas Processing Complexes

Plant	Location	Design Throughput Capacity (MMcf/d)	Natural Gas Throughput <sup>(1)</sup> (MMcf/d)	Utilization of Design Capacity <sup>(1)</sup>
<i>Marcellus Shale:</i>				
Bluestone Complex	Butler County, PA	410	310	76%
Houston Complex <sup>(2)</sup>	Washington County, PA	520	495	95%
Majorsville Complex	Marshall County, WV	1,070	905	85%
Mobley Complex	Wetzel County, WV	920	695	76%
Sherwood Complex <sup>(6)</sup>	Doddridge County, WV	1,800	1,480	102%
Total Marcellus Shale		4,720	3,885	89%
<i>Utica Shale:</i>				
Cadiz Complex <sup>(7)</sup>	Harrison County, OH	525	509	97%
Seneca Complex <sup>(7)</sup>	Noble County, OH	800	475	59%
Total Utica Shale		1,325	984	74%
<i>Southern Appalachia:</i>				
Kenova Complex <sup>(3)</sup>	Wayne County, WV	160	108	68%
Boldman Complex <sup>(3)</sup>	Pike County, KY	70	32	46%
Cobb Complex	Kanawha County, WV	65	24	37%
Kermit Complex <sup>(3)(4)</sup>	Mingo County, WV	32	N/A	N/A
Langley Complex	Langley, KY	325	101	31%
Total Southern Appalachia <sup>(4)</sup>		620	265	43%
<i>Southwest:</i>				
Carthage Complex	Panola County, TX	600	399	67%
Western Oklahoma Complex	Custer and Beckham Counties, OK	425	373	88%
Hidalgo Complex	Culberson County, TX	200	199	100%
Javelina Complex	Corpus Christi, TX	142	112	79%
Total Southwest <sup>(5)</sup>		1,367	1,083	79%
<b>Total Gas Processing</b>		<b>8,032</b>	<b>6,217</b>	<b>81%</b>

(1) Natural gas throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.

(2) Approximately 35 MMcf/d of processing capacity at the Houston Complex was decommissioned during the first quarter of 2017 and will be replaced with 200 MMcf/d of processing capacity in 2018.

(3) A portion of the gas processed at the Boldman plant, and all of the gas processed at the Kermit plant, is further processed at the Kenova plant to recover additional NGLs.

(4) The Kermit processing plant is operated by a third party solely to prevent liquids from condensing in the gathering and transmission pipelines upstream of our Kenova plant. We do not receive Kermit gas volume information but do receive all of the liquids produced at the Kermit Complex. As such, the design throughput capacity and the natural gas throughput has been excluded from the subtotal.

(5) Centrahoma processing capacity of 280 MMcf/d and actual throughput of 243 MMcf/d, that exceeded our 40 percent share of the capacity of 112 MMcf/d, are not included in this table as we own a non-operating interest.

(6) The Sherwood Complex is partially owned by Sherwood Midstream. We account for Sherwood Midstream as an equity method investment. Included in design throughput capacity is Sherwood IX which was commissioned in late December 2017. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

- (7) The Cadiz and Seneca Complexes are owned by MarkWest Utica EMG. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

### Fractionation & Condensate Stabilization Facilities

Facility	Location	Design Throughput Capacity (mbpd)	NGL Throughput <sup>(1)</sup> (mbpd)	Utilization of Design Capacity <sup>(1)</sup>
<i>Marcellus Shale:</i>				
Bluestone Complex <sup>(2)(3)</sup>	Butler County, PA	47	19	40%
Houston Complex <sup>(2)</sup>	Washington County, PA	60	61	102%
Total Marcellus Shale		107	80	75%
Hopedale Complex <sup>(2)(4)</sup>	Harrison County, OH	180	134	77%
<i>Utica Shale:</i>				
Ohio Condensate Complex <sup>(5)</sup>	Harrison County, OH	23	13	57%
Total Utica Shale		23	13	57%
<i>Southern Appalachia:</i>				
Siloam Complex <sup>(6)</sup>	South Shore, KY	24	14	58%
Total Southern Appalachia		24	14	58%
<i>Southwest:</i>				
Javelina Complex	Corpus Christi, TX	11	8	73%
Total Southwest		11	8	73%
<b>Total C3+ Fractionation and Condensate Stabilization</b>		<u>345</u>	<u>249</u>	<u>73%</u>

- (1) NGL throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.
- (2) Our Houston, Hopedale and Bluestone Complexes have above-ground NGL storage with a usable capacity of 32 million gallons, large-scale truck and rail loading. In addition, our Houston Complex has large-scale truck unloading. We also have access to up to an additional 50 million gallons of propane storage capacity that can be utilized by our assets in the Marcellus Shale, Utica Shale, and Appalachia region under an agreement with a third party that expires in 2018. Lastly, we have up to 8 million gallons of propane storage with third parties that can be utilized by our assets in the Marcellus Shale and Utica Shale.
- (3) Includes 33 mbpd of de-propanization only capacity.
- (4) The Hopedale Complex is jointly owned by Ohio Fractionation and MarkWest Utica EMG. Ohio Fractionation is a joint venture between MarkWest Liberty Midstream and Sherwood Midstream (a joint venture between MarkWest Liberty and Antero Midstream LLC). MarkWest Liberty Midstream and Sherwood Midstream are entities that operate in the Marcellus region, and MarkWest Utica EMG is an entity that operates in the Utica region. The Marcellus Operations includes its portion utilized of the jointly owned Hopedale Fractionation Complex. The Utica Operations includes Utica's portion utilized of the jointly owned Hopedale Fractionation Complex. Additionally, Sherwood Midstream has the right to fractionation revenue and the obligation to pay expenses related to 20 mbpd of capacity in the Hopedale 3 fractionator.
- (5) The Ohio Condensate Complex has up to 7 million gallons of condensate storage. The Ohio Condensate Complex is partially-owned by MarkWest Utica EMG Condensate, L.L.C. We account for Ohio Condensate as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.
- (6) Our Siloam Complex has both above-ground, pressurized NGL storage facilities, with usable capacity of two million gallons, and underground storage facilities, with usable capacity of 10 million gallons. Product

can be received by truck, pipeline or rail and can be transported from the facility by truck, rail or barge. This facility has large-scale truck and rail loading and unloading capabilities, and a river barge facility capable of loading an 860,000 gallon barge.

### De-ethanization Facilities

Facility	Location	Design Throughput Capacity (mbpd)	NGL Throughput <sup>(1)</sup> (mbpd)	Utilization of Design Capacity <sup>(1)</sup>
<i>Marcellus Shale:</i>				
Bluestone Complex	Butler County, PA	34	15	63%
Houston Complex	Washington County, PA	40	40	100%
Majorsville Complex	Marshall County, WV	80	45	99%
Mobley Complex	Wetzel County, WV	10	11	110%
Sherwood Complex	Doddridge County, WV	40	30	75%
Total Marcellus Shale		204	141	88%
<i>Utica Shale:</i>				
Cadiz Complex <sup>(2)</sup>	Harrison County, OH	40	5	13%
Total Utica Shale		40	5	13%
<i>Southwest:</i>				
Javelina Complex	Corpus Christi, TX	18	12	67%
Total Southwest		18	12	67%
<b>Total De-ethanization</b>		<b>262</b>	<b>158</b>	<b>72%</b>

(1) NGL throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.

(2) The Cadiz Complex is owned by MarkWest Utica EMG. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.

## Natural Gas Gathering Systems

System	Location	Design Throughput Capacity (MMcf/d)	Natural Gas Throughput <sup>(1)</sup> (MMcf/d)	Utilization of Design Capacity <sup>(1)</sup>
<i>Marcellus Shale:</i>				
Bluestone System	Butler County, PA	227	165	73%
Houston System	Washington County, PA	1,178	839	74%
Total Marcellus Shale		1,405	1,004	74%
<i>Utica Shale:</i>				
Ohio Gathering System <sup>(2)</sup>	Harrison, Monroe, Belmont, Guernsey and Noble Counties, OH	1,123	766	70%
Jefferson Gas System <sup>(3)</sup>	Jefferson County, OH	1,250	426	47%
Total Utica Shale		2,373	1,192	60%
<i>Southwest</i>				
East Texas System	Harrison and Panola Counties, TX	680	444	65%
Western Oklahoma System	Wheeler County, TX and Roger Mills, Ellis, Custer, Beckham and Washita Counties, OK	585	404	69%
Southeast Oklahoma System	Hughes, Pittsburg and Coal Counties, OK	755	525	70%
Eagle Ford System	Dimmit County, TX	45	30	67%
Other Systems <sup>(4)</sup>	Various	60	9	15%
Total Southwest		2,125	1,412	66%
<b>Total Natural Gas Gathering</b>		<b>5,903</b>	<b>3,608</b>	<b>66%</b>

- (1) Natural gas throughput is a weighted average for days in operation. The utilization of design capacity has been calculated using the weighted average design throughput capacity.
- (2) The Ohio Gathering System is owned by Ohio Gathering. We account for our investment in Ohio Gathering through MarkWest Utica EMG, which is accounted for as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5.
- (3) The Jefferson Gas System is owned by Jefferson Dry Gas, which is a joint venture between MarkWest Liberty Midstream and EMG MWE Dry Gas Holdings, LLC. We account for Jefferson Dry Gas as an equity method investment.
- (4) Excludes lateral pipelines where revenue is not based on throughput.

## NGL Pipelines

Pipeline	Location	Design Throughput Capacity (mbpd)	NGL Throughput (mbpd)	Utilization of Design Capacity
<i>Marcellus Shale:</i>				
Sherwood to Mobley propane and heavier liquids pipeline	Doddridge County, WV to Wetzel County, WV	75	60	80%
Mobley to Majorsville propane and heavier liquids pipeline	Wetzel County, WV to Marshall County, WV	105	85	81%
Majorsville to Houston propane and heavier liquids pipeline	Marshall County, WV to Washington County, PA	45	32	71%
Majorsville to Hopedale propane and heavier liquids pipeline	Marshall County, WV to Harrison County, OH	140	69	49%
Third-party processing plant to Bluestone ethane and heavier liquids pipeline	Butler County, PA	32	8	25%
Bluestone to Mariner West ethane pipeline <sup>(1)</sup>	Butler County, PA to Beaver County, PA	35	15	43%
Houston to Ohio River ethane pipeline <sup>(2)</sup>	Washington County, PA to Beaver County, PA	57	9	16%
Majorsville to Houston ethane pipeline <sup>(1)</sup>	Marshall County, WV to Washington County, PA	137	49	36%
Sherwood to Mobley ethane pipeline	Doddridge County, WV to Wetzel County, WV	47	30	64%
Mobley to Majorsville ethane pipeline	Wetzel County, WV to Marshall County, WV	57	41	72%
<i>Utica Shale:</i> <sup>(5)</sup>				
Seneca to Cadiz propane and heavier liquids pipeline	Noble County, OH to Harrison County, OH	75	16	21%
Cadiz to Hopedale propane and heavier liquids pipeline	Harrison County, OH	90	31	34%
Seneca to Cadiz propane/ethane and heavier liquids pipeline <sup>(4)</sup>	Noble County, OH to Harrison County, OH	69/82	1	1%
Cadiz to Atex ethane pipeline	Harrison County, OH	125	5	4%
Cadiz to Utopia ethane pipeline	Harrison County, OH	125	1	1%
<i>Appalachia:</i>				
Langley to Siloam propane and heavier liquids pipeline <sup>(3)</sup>	Langley, KY to South Shore, KY	17	12	71%
<i>Southwest:</i>				
East Texas propane and heavier liquids pipeline	Panola County, TX	39	22	56%

<sup>(1)</sup> This pipeline is FERC-regulated.

<sup>(2)</sup> This is a section of the Mariner West pipeline which is FERC-regulated and is leased to, and operated by, Sunoco.

<sup>(3)</sup> NGLs transported through the Langley to Ranger and Ranger to Kenova pipelines are combined with NGLs recovered at the Kenova Complex. The design capacity and volume reported for the Langley to Siloam pipeline represent the combined NGL stream.

<sup>(4)</sup> This pipeline from Seneca to Cadiz can only be used for either propane and heavier liquids or ethane and heavier liquids at one time. Both throughput capacities are listed above, respectively, with ethane included in the total.

<sup>(5)</sup> The Utica Shale pipelines are owned by MarkWest Utica EMG. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data—Note 5

## **Crude Oil Pipeline**

We also have a crude oil pipeline constructed in 1973 that runs from Manistee County, Michigan to Crawford County, Michigan. The design capacity throughput for this pipeline is 60 mbpd. For the year ended December 31, 2017, throughput on this pipeline was 10 mbpd, which was approximately 17 percent utilization.

## **Title to Properties**

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property and in some instance these rights-of-way are revocable at the election of the grantor. In many instances, lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where determined necessary, permits, leases, license agreements and franchise ordinances from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, as applicable, and in some instances, these permits are revocable at the election of the grantor. We also have obtained easements and license agreements from railroad companies to cross over or under railroad properties or rights-of-way, many of which are also revocable at the election of the grantor. We believe that our properties and facilities are adequate for our operations and that our facilities are adequately maintained. Many of our compression, processing, fractionation and other facilities, including our Siloam, Houston and Hopedale fractionation plants, and certain of our pipelines and other facilities, are on land that we either own in fee or that is held under long-term leases, but for any such facilities that are on land that we lease, including our Majorsville, Sarsen, Bluestone, Boldman, Kermit and Cobb processing facilities, we could be required to remove our facilities upon the termination or expiration of the leases. In addition, our L&S segment leases vehicles, building spaces, and pipeline equipment under long-term operating leases, most of which include renewal options. Our L&S segment also leases certain pipelines under a capital lease that has a fixed price purchase option in 2020.

Some of the leases, easements, rights-of-way, permits, licenses and franchise ordinances that were transferred to us required the consent of the then-current landowner to transfer these rights, which in some instances was a governmental entity. We believe that we have obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business. We also believe we have satisfactory title or other right to all of our material land assets. Title to these properties is subject to encumbrances in some cases; however, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties, or will materially interfere with their use in the operation of our business. See Item 8. Financial Statements and Supplementary Data—Note 21, for additional information regarding our leases.

Under the omnibus agreement, MPC indemnifies us for certain title defects and for failures to obtain certain consents and permits necessary to conduct our business with respect to the assets contributed to us by MPC in connection with our Initial Offering. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens that can be imposed in some jurisdictions for government-initiated action to clean up environmental contamination, liens for current taxes and other burdens, and easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our Predecessor (as defined below) or us, we believe that none of these burdens should materially detract from the value of these properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

### **Item 3. Legal Proceedings**

We are the subject of, or a party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. Some of these matters are discussed below.

#### **Litigation**

We are a party to a number of lawsuits and other proceedings and cannot predict the outcome of every such matter with certainty. While it is possible that an adverse result in one or more of the lawsuits or proceedings in which we are a defendant could be material to us, based upon current information and our experience as a defendant in other matters, we believe that these lawsuits and proceedings, individually or in the aggregate, will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

The Partnership, MarkWest, MarkWest Liberty Midstream, MarkWest Liberty Bluestone, L.L.C., Ohio Fractionation and MarkWest Utica EMG (collectively, the “MPLX Parties”) are parties to various lawsuits with Bilfinger Westcon, Inc. (“Westcon”) that were instituted in 2016 and 2017 in the Court of Common Pleas in Butler County, Pennsylvania, the Circuit Court in Wetzel County, West Virginia, and the Court of Common Pleas in Harrison County, Ohio. The lawsuits relate to disputes regarding construction work performed by Westcon at the Bluestone, Mobley and Cadiz processing complexes in Pennsylvania, West Virginia and Ohio, respectively, and the Hopedale fractionation complex in Ohio. With respect to work performed by Westcon at the Mobley and Bluestone processing complexes, one or more of the MPLX Parties have asserted breach of contract, fraud, and with respect to work performed at the Mobley processing complex, MarkWest Liberty Midstream has also asserted negligent misrepresentation claims against Westcon. Westcon has also asserted claims against one or more of the MPLX Parties regarding these construction projects for breach of contract, unjust enrichment, promissory estoppel, fraud and constructive fraud, tortious interference with contractual relations, and civil conspiracy. The MPLX Parties seek in excess of \$10 million, plus an unspecified amount of punitive damages. Westcon seeks in excess of \$40 million, plus an unspecified amount of punitive damages. It is possible that, in connection with these lawsuits, the MPLX Parties will incur material amounts of damages. While the ultimate outcome and impact to the Partnership cannot be predicted with certainty, and the Partnership is not able to provide a reasonable estimate of the potential loss (or range of loss), if any, for these claims, the Partnership believes the resolution of these claims will not have a material adverse effect on its consolidated financial position, results of operations, or cash flows.

In 2003, the State of Illinois brought an action against the Premcor Refining Group, Inc. (“Premcor”) and Apex Refining Company (“Apex”) asserting claims for environmental cleanup related to the refinery owned by these entities in the Hartford/Wood River, Illinois area. In 2006, Premcor and Apex filed third-party complaints against numerous owners and operators of petroleum products facilities in the Hartford/Wood River, Illinois area, including MPL. These complaints, which have been amended since filing, assert claims of common law nuisance and contribution under the Illinois Contribution Act and other laws for environmental cleanup costs that may be imposed on Premcor and Apex by the State of Illinois. On September 6, 2016, the trial court approved a settlement between Apex and the State of Illinois whereby Apex agreed to settle all claims against it for a \$10 million payment. Premcor has objected to this ruling and is seeking an appeal. There are several third-party defendants in the litigation and MPL has asserted cross-claims in contribution against the various third-party defendants. This litigation is currently pending in the Third Judicial Circuit Court, Madison County, Illinois. The State’s case against Premcor is currently scheduled to commence trial on June 25, 2018 and Premcor’s claims against third-party defendants, including MPL, is currently scheduled to commence August 13, 2018. While the ultimate outcome of these litigated matters remains uncertain, neither the likelihood of an unfavorable outcome nor the ultimate liability, if any, with respect to this matter can be determined at this time and the Partnership is unable to estimate a reasonably possible loss (or range of loss) for this litigation. Under the omnibus agreement, MPC will indemnify the Partnership for the full cost of any losses should MPL be deemed responsible for any damages in this lawsuit.



## **Environmental Proceedings**

The Illinois Environmental Protection Agency (“IEPA”) initiated an enforcement action against MPL, in connection with an April 17, 2016 pipeline release to the Wabash River near Crawleyville, Indiana. MPL responded to a Clean Water Act request for information from the EPA in furtherance of its investigation of possible violations arising from the April 17, 2016 pipeline release. MPL has entered into joint settlement negotiations with the IEPA and the EPA and reached a settlement in principle for payment of a total civil penalty of \$335,000.

In July 2015, representatives from the EPA and the United States Department of Justice conducted a search at a MarkWest Liberty Midstream pipeline launcher/receiver site utilized for pipeline maintenance operations in Washington County, Pennsylvania pursuant to a search warrant. The criminal investigation ended without any charges against MarkWest Liberty Midstream. With respect to the civil enforcement allegations associated with permitting or other related regulatory obligations for its launcher/receiver and compressor station facilities in the region, MarkWest Liberty Midstream and its affiliates have agreed in principle to pay a cash penalty of approximately \$0.6 million and to undertake certain supplemental environmental projects with an estimated cost of approximately \$2.4 million.

We are involved in a number of other environmental proceedings arising in the ordinary course of business. While the ultimate outcome and impact on us cannot be predicted with certainty, we believe the resolution of these environmental proceedings will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

## **Item 4. Mine Safety Disclosures**

Not applicable

## Part II

### Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common limited partner units are listed on the NYSE and traded under the symbol "MPLX." As of February 16, 2018, there were 323 registered holders of 289,117,174 outstanding common units held by the public, including 287,997,480 common units held in street name. In addition, as of February 16, 2018, MPC and its affiliates owned 504,701,934 of our common units, constituting approximately 64 percent of the outstanding common units. In addition, MPC, through our general partner owns the non-economic general partnership interest in us.

The following table reflects intraday high and low sales prices of and cash distributions declared on our common units by quarter over the last two fiscal years.

Quarter ended	Trading prices per common unit		Quarterly cash distribution per unit <sup>(1)</sup>	Distribution date	Record date
	High	Low			
December 31, 2017	\$38.47	\$32.00	\$0.6075	February 14, 2018	February 5, 2018
September 30, 2017	36.80	32.17	0.5875	November 14, 2017	November 6, 2017
June 30, 2017	37.85	30.88	0.5625	August 14, 2017	August 7, 2017
March 31, 2017	39.43	34.13	0.5400	May 15, 2017	May 8, 2017
December 31, 2016	35.32	30.09	0.5200	February 14, 2017	February 6, 2017
September 30, 2016	35.12	30.36	0.5150	November 14, 2016	November 4, 2016
June 30, 2016	34.92	26.75	0.5100	August 12, 2016	August 2, 2016
March 31, 2016	39.46	16.34	0.5050	May 13, 2016	May 3, 2016

<sup>(1)</sup> Represents cash distributions attributable to the quarter and declared and paid in accordance with our Partnership Agreement and as amended.

#### Distributions of Available Cash

Our Partnership Agreement requires that, within 60 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date.

*Definition of available cash.* Available cash is defined in our Partnership Agreement. Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business (including reserves for our future capital expenditures and for anticipated future credit needs);
  - comply with applicable law, any of our debt instruments or other agreements or obligations; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all common units for the current quarter);
- plus, if our general partner so determines, all or any portion of the cash on hand resulting from working capital borrowings made subsequent to the end of such quarter.

*Intent to Distribute the Minimum Quarterly Distribution.* Under our current cash distribution policy, we intend to make a minimum quarterly distribution to the holders of our common units of \$0.2625 per unit, or \$1.05 per unit

on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. The amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our Partnership Agreement. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Debt and Liquidity Overview, for a discussion of the restrictions included in our bank revolving credit facility that may restrict our ability to make distributions.

### **Preferred Unit Distributions**

The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to \$0.528125 per unit for any quarter ending on or before May 13, 2018, and thereafter will be entitled to receive quarterly distributions on each Preferred unit equal to the greater of \$0.528125 per unit or the amount that each Preferred unit would have otherwise received if it had been converted into common units at the then-applicable Preferred unit conversion rate. The Partnership may not pay any distributions for any quarter on any junior securities, including any of the common units, unless the distribution payable to the Preferred units with respect to such quarter, together with any previously accrued and unpaid distributions to the Preferred units, have been paid in full.

### **Recent Sales of Unregistered Units**

In connection with the issuance of 84,658 common units upon vesting of phantom units under the MPLX LP 2012 Incentive Compensation Plan, our general partner purchased an aggregate of 1,727 general partner units for \$62,125.69 in cash during the three months ended December 31, 2017, to maintain its two percent general partner interest in us. The general partner units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended.

## Item 6. Selected Financial Data

The following table shows selected historical consolidated financial data of MPLX LP as of the dates and for the years indicated. On May 1, 2013, we acquired a five percent interest in Pipe Line Holdings, resulting in a 56 percent indirect ownership interest at December 31, 2013. We then acquired a 13 percent interest in Pipe Line Holdings on March 1, 2014, and a 30.5 percent interest on December 1, 2014, resulting in a 99.5 percent indirect ownership interest at December 31, 2014. The remaining 0.5 percent interest was purchased on December 4, 2015. On this same date, a wholly-owned subsidiary of MPLX LP merged with MarkWest. This information includes periods prior to the acquisition of HSM, which occurred on March 31, 2016, and prior to the acquisition of HST, WHC and MPLXT, which occurred on March 1, 2017.

The following table also presents the non-GAAP financial measures of Adjusted EBITDA and DCF, which we use in our business. For the definitions of Adjusted EBITDA and DCF and a reconciliation to our most directly comparable financial measures calculated and presented in accordance with GAAP, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations.

<i>(In millions, except per unit data)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>
<b>Consolidated Statements of Income Data</b>					
Total revenues and other income	\$ 3,867	\$ 3,029	\$ 1,101	\$ 793	\$ 713
Income from operations	1,191	683	381	245	213
Net income	836	434	333	239	211
Net income attributable to MPLX LP	794	233	156	121	78
Limited partners' interest in net income attributable to MPLX LP	411	1	99	115	76
<b>Per Unit Data</b>					
Net income attributable to MPLX LP per limited partner unit (basic and diluted):					
Common—basic	\$ 1.07	\$ —	\$ 1.23	\$ 1.55	\$ 1.05
Common—diluted	1.06	—	1.22	1.55	1.05
Subordinated—basic and diluted	—	—	0.11	1.50	1.01
Cash distributions declared per limited partner common unit	\$2.2975	\$2.0500	\$1.8200	\$1.4100	\$1.1675
<b>Consolidated Balance Sheets Data (at period end)</b>					
Property, plant and equipment, net	\$12,187	\$11,408	\$10,214	\$ 1,324	\$ 1,248
Total assets	19,500	17,509	16,404	1,544	1,504
Long-term debt, including capital leases <sup>(3)</sup>	6,945	4,422	5,255	644	10
Redeemable preferred units	1,000	1,000	—	—	—
<b>Consolidated Statements of Cash Flows Data</b>					
Net cash provided by (used in):					
Operating activities	\$ 1,907	\$ 1,491	\$ 427	\$ 335	\$ 297
Investing activities	(2,307)	(1,413)	(1,686)	(137)	(158)
Financing activities	171	113	1,275	(225)	(302)
Additions to property, plant and equipment <sup>(1)</sup>	1,411	1,313	334	141	151
<b>Other Financial Data</b>					
Adjusted EBITDA attributable to MPLX LP <sup>(2)(4)</sup>	\$ 2,004	\$ 1,419	\$ 498	\$ 166	\$ 111
DCF attributable to MPLX LP <sup>(2)(4)</sup>	1,628	1,140	399	137	114

<sup>(1)</sup> Represents cash capital expenditures as reflected on Consolidated Statements of Cash Flows for the periods indicated, which are included in cash used in investing activities.

<sup>(2)</sup> The 2015 Adjusted EBITDA attributable to MPLX LP includes pre-merger EBITDA from MarkWest and the 2015 DCF includes undistributed DCF from MarkWest. For a discussion of the non-GAAP financial

measures of Adjusted EBITDA and DCF and a reconciliation of Adjusted EBITDA and DCF to our most directly comparable measures calculated and presented in accordance with GAAP, see Item 7.

Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations.

- (3) During 2015, in connection with the MarkWest Merger, MPLX LP assumed MarkWest senior notes with an aggregate principal amount of \$4.1 billion and used its credit facility to repay \$850 million of the \$943 million of borrowings under MarkWest's credit facility.
- (4) For all years presented, Predecessor is excluded from Adjusted EBITDA attributable to MPLX LP and DCF attributable to MPLX LP.

## Operating Data

	2017	2016	2015	2014	2013
<b>L&amp;S</b>					
<b>Crude oil transported for (mbpd)<sup>(1)</sup>:</b>					
MPC	1,622	1,461	1,443	838	853
Third parties	314	182	197	203	222
Total	1,936	1,643	1,640	1,041	1,075
% MPC	84%	89%	88%	80%	79%
<b>Products transported for (mbpd)<sup>(2)</sup>:</b>					
MPC <sup>(3)</sup>	928	844	966	852	862
Third parties	157	146	27	26	49
Total	1,085	990	993	878	911
% MPC	86%	85%	97%	97%	95%
<b>Average tariff rates (\$ per Bbl)<sup>(4)</sup>:</b>					
Crude oil pipelines	0.56	0.57	0.55	0.64	0.60
Product pipelines	0.74	0.68	0.65	0.61	0.56
Total pipelines	0.63	0.61	0.59	0.63	0.58
Terminal throughput (mbpd) <sup>(5)</sup>	1,477	1,505	N/A	N/A	N/A
<b>Marine Assets (number in operation)<sup>(6)</sup></b>					
Barges	232	222	219	211	200
Towboats	18	18	18	18	17
<b>G&amp;P<sup>(7)</sup></b>					
<b>Gathering Throughput (MMcf/d)</b>					
Marcellus Operations	1,004	910	889		
Utica Operations <sup>(8)</sup>	1,192	932	745		
Southwest Operations <sup>(9)</sup>	1,412	1,433	1,441		
Total gathering throughput	3,608	3,275	3,075		
<b>Natural Gas Processed (MMcf/d)</b>					
Marcellus Operations	3,885	3,210	2,964		
Utica Operations <sup>(8)</sup>	984	1,072	1,136		
Southwest Operations <sup>(14)</sup>	1,326	1,226	1,125		
Southern Appalachian Operations	265	253	243		
Total natural gas processed	6,460	5,761	5,468		
<b>C2 + NGLs Fractionated (mbpd)</b>					
Marcellus Operations <sup>(10)</sup>	320	260	220		
Utica Operations <sup>(8)(10)</sup>	40	42	51		
Southwest Operations	20	18	24		
Southern Appalachian Operations <sup>(11)</sup>	14	15	12		
Total C2 + NGLs fractionated <sup>(12)</sup>	394	335	307		
<b>Pricing Information</b>					
Natural Gas NYMEX HH (\$/MMBtu)	3.02	2.55	2.04		
C2 + NGL Pricing/Gal <sup>(13)</sup>	0.66	0.47	0.40		

(1) Represents the average aggregate daily number of barrels of crude oil transported on our pipelines and at our Wood River barge dock for MPC and for third parties. Volumes shown are 100 percent of the volumes transported on the pipelines and barge dock.

- (2) Represents the average aggregate daily number of barrels of products transported on our pipelines for MPC and third parties. Volumes shown are 100 percent of the volumes transported on the pipelines.
- (3) Includes volumes shipped by MPC on various pipelines under joint tariffs with third parties. For accounting purposes, revenue attributable to these volumes is classified as third-party revenue because we receive payment from those third parties with respect to volumes shipped under the joint tariffs; however, the volumes associated with this revenue are applied towards MPC's minimum quarterly volume commitments on the applicable pipelines because MPC is the shipper of record.
- (4) Average tariff rates calculated using pipeline transportation revenues divided by pipeline throughput barrels.
- (5) Throughput reported for 2016 represents average volumes for the nine months beginning April 1, 2016.
- (6) Represents total at the end of the period.
- (7) G&P volumes reported for 2015 represent the average volumes after the close of the MarkWest Merger.
- (8) Includes unconsolidated equity method investments that are shown consolidated for segment purposes only.
- (9) Includes approximately 173 MMcf/d, 309 MMcf/d and 310 MMcf/d related to our unconsolidated equity method investments, Wirth and MarkWest Pioneer, for the years ended December 31, 2017, 2016 and 2015, respectively. The Partnership acquired a 100 percent interest in MarkWest Pioneer on July 1, 2017.
- (10) Hopedale is jointly owned by Ohio Fractionation and MarkWest Utica EMG. Ohio Fractionation is a subsidiary of MarkWest Liberty Midstream. MarkWest Liberty Midstream and MarkWest Utica EMG are entities that operate in the Marcellus and Utica regions, respectively. The Marcellus Operations includes its portion utilized of the jointly owned Hopedale Fractionation Complex. The Utica Operations includes Utica's portion utilized of the jointly owned Hopedale Fractionation Complex. Additionally, Sherwood Midstream has the right to fractionation revenue and the obligation to pay expenses related to 20 mbpd of capacity in the Hopedale 3 fractionator.
- (11) Includes NGLs fractionated for the Marcellus and Utica Operations.
- (12) Purity ethane makes up approximately 165 mbpd, 128 mbpd and 104 mbpd of total fractionated products for the years ended December 31, 2017, 2016 and 2015, respectively.
- (13) C2 + NGL pricing based on Mont Belvieu prices assuming an NGL barrel of approximately 35 percent ethane, 35 percent propane, six percent Iso-Butane, 12 percent normal butane and 12 percent natural gasoline.
- (14) Includes Centrahoma, an unconsolidated equity method investment that is non-operated and is shown 100 percent in the above table for segment purposes only.

## **Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations**

Management’s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information included under Item 1. Business, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data.

Management’s Discussion and Analysis of Financial Condition and Results of Operations includes various forward-looking statements concerning trends or events potentially affecting our business. You can identify our forward-looking statements by words such as “anticipate,” “believe,” “estimate,” “objective,” “expect,” “forecast,” “goal,” “intend,” “plan,” “predict,” “project,” “potential,” “seek,” “target,” “could,” “may,” “should,” “would,” “will” or other similar expressions that convey the uncertainty of future events or outcomes. In accordance with “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements.

### **PARTNERSHIP OVERVIEW**

We are a diversified, growth-oriented MLP formed by MPC to own, operate, develop and acquire midstream energy infrastructure assets. We are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the gathering, transportation, and storage of crude oil and refined petroleum products.

### **SIGNIFICANT FINANCIAL AND OTHER HIGHLIGHTS**

During 2017, we continued to focus on our long-term objectives of delivering a sustainable distribution growth rate that provides attractive total returns to our unitholders, driving a lower cost of capital, developing our organic growth projects, maintaining our investment grade credit profile and becoming a consolidator in the midstream space. Significant financial and other highlights for the year ended December 31, 2017, are listed below. Refer to Results of Operations and Liquidity and Capital Resources for further details.

- L&S segment operating income attributable to MPLX LP increased approximately \$329 million, or 73 percent, in 2017 compared to 2016. This increase was primarily due to \$270 million of operating income generated by HST, WHC and MPLXT following the March 1, 2017 acquisition, \$35 million from the inclusion of HSM for the first quarter of 2017, along with approximately \$27 million from the acquisition of the Ozark pipeline.
- G&P segment operating income attributable to MPLX LP increased approximately \$203 million, or 18 percent, in 2017 compared to 2016. This increase was predominately due to \$170 million from increased gathered, processed and fractionated volumes, which drove higher utilization rates, as a result of expansions in the Southwest, as well as growth at the Sherwood, Majorsville and Bluestone (previously referred to as Keystone) plants. Further, there was an increase in product margins of \$63 million as compared to 2016, offset by increased facility expenses. Compared to full-year 2016, gathering volumes were up 10 percent, processing volumes were up 12 percent and fractionated volumes were up 18 percent.

Additional highlights for the year ended December 31, 2017, including a look ahead to anticipated growth, are listed below.

### **Dropdown Acquisitions from MPC**

In early 2017, MPC announced plans to offer MLP-qualifying midstream assets and services to the Partnership, projected to generate \$1.4 billion of annual EBITDA. Two of the three planned dropdown transactions, projected



to generate \$388 million of annual EBITDA, occurred during the first and third quarters of 2017. The third planned dropdown transaction, projected to generate \$1.0 billion of annual EBITDA, occurred in the first quarter of 2018. The stable, fee-based earnings from these acquisitions, as described below, add both scale and diversification to our portfolio of high-quality midstream assets.

- On February 1, 2018, we acquired Refining Logistics and Fuels Distribution from MPC in exchange for \$4.1 billion in cash and a fixed number of common units and general partner units of 111.6 million and 2.3 million, respectively. The general partner units maintained MPC's two percent economic general partner interest, which converted into a non-economic general partner interest immediately thereafter in the GP IDR Exchange. Refining Logistics contains the integrated tank farm assets that support MPC's refining operations. These essential logistics assets include: approximately 56 million barrels storage capacity (crude, finished products and intermediates), 619 tanks, 32 rail and truck racks, 18 docks, and gasoline blenders. Fuels Distribution is structured to provide a broad range of scheduling and marketing services as MPC's sole and exclusive agent. See Financing Activities below, and Item 8. Financial Statements and Supplementary Data—Note 24 for additional information.
- On September 1, 2017, we acquired joint-interest ownerships in certain pipelines and storage facilities from MPC for \$420 million in cash and a fixed number of common units and general partner units of 18.5 million and 0.4 million, respectively. The general partner units maintained MPC's two percent economic general partner interest. The acquired ownership interests included a 35 percent ownership interest in Illinois Extension, a 41 percent ownership interest in LOOP, a 59 percent ownership interest in LOCAP, and a 25 percent ownership interest in Explorer (collectively, the "Joint-Interest Acquisition"). As of the acquisition date, the assets held by these entities include a 1,830-mile refined products pipeline, storage facilities, pump stations, and a deepwater oil port, located offshore of Louisiana. The infrastructure serves primarily the Midwest and Gulf Coast regions of the United States.
- On March 1, 2017, we acquired certain pipeline, storage and terminal assets from MPC for \$1.5 billion in cash and a fixed number of common units and general partner units of 13.0 million and 0.3 million, respectively. The general partner units maintained MPC's two percent economic general partner interest. As of the acquisition date, the assets consisted of 174 miles of crude oil pipelines and 430 miles of refined products pipelines, nine butane and propane storage caverns located in Michigan with approximately 1.8 million barrels of NGL storage capacity, 59 terminals for the receipt, storage, blending, additization, handling and redelivery of refined petroleum products, along with one leased terminal and partial ownership interest in two terminals. Collectively, the 62 terminals had a combined total shell capacity of approximately 23.6 million barrels. The terminal facilities are located primarily in the Midwest, Gulf Coast and Southeast regions of the United States.

### **Other Significant Acquisitions and Investments**

- On March 1, 2017, we purchased the 433-mile, 22-inch Ozark crude oil pipeline for \$219 million. The pipeline is capable of transporting approximately 230 mbpd and expands the footprint of our logistics and storage segment by connecting Cushing, Oklahoma-sourced volumes to our extensive Midwest pipeline network. An expansion project to increase the line's capacity to approximately 360 mbpd is targeted for completion in mid-2018.
- On February 15, 2017, we acquired a 9.1875 percent indirect equity interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Company Pipeline projects, collectively referred to as the Bakken Pipeline system, for an initial investment of \$500 million. The Bakken Pipeline system is capable of transporting more than 520 mbpd of crude oil from the Bakken/Three Forks production area in North Dakota to the Midwest through Patoka, Illinois and ultimately to the Gulf Coast.
- Effective January 1, 2017, we formed a strategic joint venture with Antero Midstream to process natural gas at the Sherwood Complex and fractionate natural gas liquids at the Hopedale Complex. We believe this unique transaction strengthens our long-term relationship with the largest producer in the

Appalachian Basin and provides the Partnership with substantial future growth opportunities. As part of this agreement, Antero Midstream released to the joint venture the dedication of approximately 195,000 gross operated acres located in Tyler, Wetzel and Ritchie counties of West Virginia. We contributed cash of \$20 million, along with \$353 million of assets, comprised of real property, equipment and facilities, including three 200 MMcf/d gas processing plants then under construction at the Sherwood Complex. Antero Midstream contributed cash of \$154 million. The joint venture commenced operations of the first new facility during the first quarter of 2017, the second new facility during the third quarter of 2017 and the third new facility late in the fourth quarter of 2017. Construction of the fourth and fifth new facilities has been announced and are expected to commence operations in the last half of 2018. In addition to the five new processing facilities, the joint venture contemplates the development of up to another six processing facilities to support Antero Resources, which would be located at both the Sherwood Complex and a new location in West Virginia. At the Hopedale Complex, the largest fractionation facility in the Marcellus and Utica shales, the joint venture will also support the growth of Antero Resources' NGL production by investing in 20 mbpd of existing fractionation capacity, with options to invest in future fractionation expansions.

### Financing Activities

- On February 8, 2018, the Partnership issued \$5.5 billion of senior notes in a public offering, consisting of \$500 million aggregate principal amount of 3.375 percent unsecured senior notes due March 2023, \$1.25 billion aggregate principal amount of 4.0 percent unsecured senior notes due March 2028, \$1.75 billion aggregate principal amount of 4.5 percent unsecured senior notes due April 2038, \$1.5 billion aggregate principal amount of 4.7 percent unsecured senior notes due April 2048, and \$500 million aggregate principal amount of 4.9 percent unsecured senior notes due April 2058. The notes were offered at a price to the public of 99.931 percent, 99.551 percent, 98.811 percent, 99.348 percent, and 99.289 percent of par, respectively. The net proceeds were used to repay the 364-day term loan facility of \$4.1 billion, the outstanding borrowings under the credit agreement and the intercompany loan agreement with MPC Investment, as well as for general partnership purposes.
- On February 1, 2018, immediately following the completion of the dropdown acquisitions mentioned above, our general partner's IDR's were eliminated and its two percent economic general partner interest in MPLX LP was converted into a non-economic general partner interest, all in exchange for 275 million newly issued MPLX LP common units. This exchange eliminates the general partner cash distribution requirements of the Partnership and is expected to be accretive to DCF attributable to common unitholders in the third quarter and for the full year 2018.
- On February 1, 2018, in connection with the dropdown acquisition, the Partnership drew \$4.1 billion on a 364-day term loan facility with a syndicate of lenders, which was entered into on January 2, 2018. The proceeds of the term loan facility were used to fund the cash portion of the dropdown consideration.
- On July 21, 2017, we entered into a credit agreement to replace our previous \$2.0 billion five-year bank revolving credit facility with a \$2.25 billion five-year bank revolving credit facility that expires in July 2022. Additionally, on July 19, 2017, we repaid the entire outstanding principal amount of our \$250 million term loan with cash on hand. For further discussion, see Item 8. Financial Statements and Supplementary Data—Note 17.
- On February 10, 2017, we completed a public offering of \$2.25 billion aggregate principal amount of senior notes. For further discussion, see Item 8. Financial Statements and Supplementary Data—Note 17.
- During the year ended December 31, 2017, we issued an aggregate of 13,846,998 commons units under our ATM Program, generating net proceeds of approximately \$473 million, all of which transactions were executed during the first half of the year.

Refer to Item 1. Business—Recent Developments and Liquidity and Capital Resources for further details concerning the above-listed announcements.

## **NON-GAAP FINANCIAL INFORMATION**

Our management uses a variety of financial and operating metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include the non-GAAP financial measures of Adjusted EBITDA and DCF. The amount of Adjusted EBITDA and DCF generated is considered by the board of directors of our general partner in approving the Partnership's cash distributions.

We define Adjusted EBITDA as net income adjusted for (i) depreciation and amortization; (ii) provision (benefit) for income taxes; (iii) amortization of deferred financing costs; (iv) non-cash equity-based compensation; (v) impairment expense; (vi) net interest and other financial costs; (vii) (income) loss from equity method investments; (viii) distributions from unconsolidated subsidiaries; (ix) distributions of cash received from equity method investments to MPC; (x) unrealized derivative losses (gains); (xi) other adjustments to equity method investment distributions; and (xii) acquisition costs. We also use DCF, which we define as Adjusted EBITDA adjusted for (i) deferred revenue impacts; (ii) net interest and other financial costs; (iii) maintenance capital expenditures; (iv) equity method investment capital expenditures paid out; and (v) other non-cash items. The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.

We believe that the presentation of Adjusted EBITDA and DCF provides useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA and DCF are net income and net cash provided by operating activities. Adjusted EBITDA and DCF should not be considered alternatives to GAAP net income or net cash provided by operating activities. Adjusted EBITDA and DCF have important limitations as analytical tools because they exclude some but not all items that affect net income and net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted EBITDA and DCF should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDA and DCF may be defined differently by other companies in our industry, our definitions of Adjusted EBITDA and DCF may not be comparable to similarly titled measures of other companies, thereby diminishing their utility. For a reconciliation of Adjusted EBITDA and DCF to their most directly comparable measures calculated and presented in accordance with GAAP, see Results of Operations.

Management evaluates contract performance on the basis of net operating margin, a non-GAAP financial measure, which is defined as segment revenue less purchased product costs less derivative gains (losses) related to purchased product costs. These charges have been excluded for the purpose of enhancing the understanding by both management and investors of the underlying baseline operating performance of our contractual arrangements, which management uses to evaluate our financial performance for purposes of planning and forecasting. Net operating margin does not have any standardized definition and, therefore, is unlikely to be comparable to similar measures presented by other reporting companies. Net operating margin results should not be evaluated in isolation of, or as a substitute for, our financial results prepared in accordance with GAAP. Our use of net operating margin and the underlying methodology in excluding certain charges is not necessarily an indication of the results of operations expected in the future, or that we will not, in fact, incur such charges in future periods.

In evaluating our financial performance, management utilizes the segment performance measures, segment revenues and segment operating income, including total segment operating income. The use of these measures allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. See Item 8. Financial Statements and Supplementary Data—Note 10 for the

reconciliations of these segment measures, including total segment operating income, to their respective most directly comparable GAAP measures.

### **COMPARABILITY OF OUR FINANCIAL RESULTS**

Our acquisitions, sale of certain assets to newly formed joint ventures, and impairments have impacted comparability of our financial results (see Item 8. Financial Statements and Supplementary Data—Notes 4, 5 and 18).

## RESULTS OF OPERATIONS

The following table and discussion is a summary of our results of operations for the years ended 2017, 2016 and 2015, including a reconciliation of Adjusted EBITDA and DCF from net income and net cash provided by operating activities, the most directly comparable GAAP financial measures. Prior period financial information has been retrospectively adjusted for the acquisition of HSM, HST, WHC and MPLXT.

<i>(In millions)</i>	2017	2016	\$ Change	2015	\$ Change
<b>Revenues and other income:</b>					
Service revenue	\$1,156	\$ 958	\$ 198	\$ 130	\$ 828
Service revenue—related parties	1,082	936	146	701	235
Rental income	277	298	(21)	20	278
Rental income—related parties	279	235	44	146	89
Product sales	889	572	317	36	536
Product sales—related parties	8	11	(3)	1	10
Gain on sale of assets	—	1	(1)	—	1
Income (loss) from equity method investments <sup>(1)</sup>	78	(74)	152	3	(77)
Other income	6	6	—	6	—
Other income—related parties	92	86	6	58	28
Total revenues and other income	<u>3,867</u>	<u>3,029</u>	<u>838</u>	<u>1,101</u>	<u>1,928</u>
<b>Costs and expenses:</b>					
Cost of revenues (excludes items below)	528	454	74	247	207
Purchased product costs	651	448	203	20	428
Rental cost of sales	62	57	5	11	46
Rental cost of sales—related parties	2	1	1	1	—
Purchases—related parties	455	388	67	172	216
Depreciation and amortization	683	591	92	129	462
Impairment expense	—	130	(130)	—	130
General and administrative expenses	241	227	14	125	102
Other taxes	54	50	4	15	35
Total costs and expenses	<u>2,676</u>	<u>2,346</u>	<u>330</u>	<u>720</u>	<u>1,626</u>
<b>Income from operations</b>	1,191	683	508	381	302
Related party interest and other financial costs	2	1	1	—	1
Interest expense (net of amounts capitalized)	296	210	86	35	175
Other financial costs	56	50	6	12	38
<b>Income before income taxes</b>	837	422	415	334	88
Provision (benefit) for income taxes	1	(12)	13	1	(13)
<b>Net income</b>	836	434	402	333	101
Less: Net income attributable to noncontrolling interests	6	2	4	1	1
Less: Net income attributable to Predecessor	36	199	(163)	176	23
<b>Net income attributable to MPLX LP</b>	<u>\$ 794</u>	<u>\$ 233</u>	<u>\$ 561</u>	<u>\$ 156</u>	<u>\$ 77</u>
<b>Adjusted EBITDA attributable to MPLX LP<sup>(2)</sup></b>	\$2,004	\$1,419	\$ 585	\$ 498	\$ 921
<b>DCF<sup>(2)</sup></b>	\$1,628	\$1,140	\$ 488	\$ 399	\$ 741
<b>DCF attributable to GP and LP unitholders<sup>(2)</sup></b>	\$1,563	\$1,099	\$ 464	\$ 399	\$ 700

(1) Includes an impairment expense of \$89 million related to one of the Partnership's equity method investments for the year ended December 31, 2016.

(2) Non-GAAP financial measure. See the following tables for reconciliations to the most directly comparable GAAP measures.

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation of Adjusted EBITDA attributable to MPLX LP and DCF attributable to GP and LP unitholders from Net income:</b>			
<b>Net income</b>	\$ 836	\$ 434	\$ 333
Depreciation and amortization	683	591	129
Provision (benefit) for income taxes	1	(12)	1
Amortization of deferred financing costs	53	46	5
Non-cash equity-based compensation	15	10	4
Impairment expense	—	130	—
Net interest and other financial costs	301	215	42
(Income) loss from equity method investments <sup>(1)</sup>	(78)	74	(3)
Distributions from unconsolidated subsidiaries	241	148	15
Distributions of cash received from Joint-Interest Acquisition entities to MPC	(31)	—	—
Other adjustments to equity method investment distributions	21	2	—
Unrealized derivative losses (gains) <sup>(2)</sup>	6	36	(4)
Acquisition costs	11	(1)	30
<b>Adjusted EBITDA</b>	<u>2,059</u>	<u>1,673</u>	<u>552</u>
Adjusted EBITDA attributable to noncontrolling interests	(8)	(3)	(1)
Adjusted EBITDA attributable to Predecessor <sup>(3)</sup>	(47)	(251)	(215)
MarkWest's pre-merger EBITDA <sup>(4)</sup>	—	—	162
<b>Adjusted EBITDA attributable to MPLX LP</b>	<u>2,004</u>	<u>1,419</u>	<u>498</u>
Deferred revenue impacts	33	16	6
Net interest and other financial costs	(301)	(215)	(35)
Maintenance capital expenditures	(103)	(84)	(49)
Equity method investment capital expenditures paid out	(13)	(3)	—
Other	6	(1)	(6)
Portion of DCF adjustments attributable to Predecessor <sup>(3)</sup>	2	8	17
<b>DCF pre-MarkWest undistributed</b>	<u>1,628</u>	<u>1,140</u>	<u>431</u>
MarkWest undistributed DCF <sup>(4)</sup>	—	—	(32)
<b>DCF</b>	<u>1,628</u>	<u>1,140</u>	<u>399</u>
Preferred unit distributions	(65)	(41)	—
<b>DCF attributable to GP and LP unitholders</b>	<u><u>\$1,563</u></u>	<u><u>\$1,099</u></u>	<u><u>\$ 399</u></u>

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation of Adjusted EBITDA attributable to MPLX LP and DCF attributable to GP and LP unitholders from Net cash provided by operating activities:</b>			
<b>Net cash provided by operating activities</b>	\$1,907	\$1,491	\$ 427
Changes in working capital items	(147)	(76)	59
All other, net	(28)	(16)	(7)
Non-cash equity-based compensation	15	10	4
Net gain on disposal of assets	—	1	—
Net interest and other financial costs	301	215	42
Current income taxes	2	5	—
Asset retirement expenditures	2	6	1
Unrealized derivative losses (gains) <sup>(2)</sup>	6	36	(4)
Acquisition costs	11	(1)	30
Distributions of cash received from Joint-Interest Acquisition entities to MPC	(31)	—	—
Other adjustments to equity method investment distributions	21	2	—
<b>Adjusted EBITDA</b>	<u>2,059</u>	<u>1,673</u>	<u>552</u>
Adjusted EBITDA attributable to noncontrolling interests	(8)	(3)	(1)
Adjusted EBITDA attributable to Predecessor <sup>(3)</sup>	(47)	(251)	(215)
MarkWest's pre-merger EBITDA <sup>(4)</sup>	—	—	162
<b>Adjusted EBITDA attributable to MPLX LP</b>	<u>2,004</u>	<u>1,419</u>	<u>498</u>
Deferred revenue impacts	33	16	6
Net interest and other financial costs	(301)	(215)	(35)
Maintenance capital expenditures	(103)	(84)	(49)
Equity method investment capital expenditures paid out	(13)	(3)	—
Other	6	(1)	(6)
Portion of DCF adjustments attributable to Predecessor <sup>(3)</sup>	2	8	17
<b>DCF pre-MarkWest undistributed</b>	<u>1,628</u>	<u>1,140</u>	<u>431</u>
MarkWest undistributed DCF <sup>(4)</sup>	—	—	(32)
<b>DCF</b>	<u>1,628</u>	<u>1,140</u>	<u>399</u>
Preferred unit distributions	(65)	(41)	—
<b>DCF attributable to GP and LP unitholders</b>	<u>\$1,563</u>	<u>\$1,099</u>	<u>\$ 399</u>

- (1) Includes an impairment expense of \$89 million related to one of the Partnership's equity method investments for the year ended December 31, 2016.
- (2) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.
- (3) The Adjusted EBITDA and DCF adjustments related to Predecessor are excluded from Adjusted EBITDA attributable to MPLX LP and DCF prior to the acquisition dates.
- (4) The financial and operational results of MarkWest are included in the Partnership's results from December 4, 2015, the date of the MarkWest Merger, in accordance with GAAP. The Partnership distributes and, prior to the MarkWest Merger, MarkWest distributed, all or a portion of the DCF generated in any given quarter to unitholders in the subsequent quarter. MarkWest had made a distribution for the third quarter of 2015 prior to the MarkWest Merger. However, the DCF generated by MarkWest for the period from October 1, 2015 through December 3, 2015 had not been distributed to MarkWest unitholders as of the date of the MarkWest Merger. By operation of the MarkWest Merger, the Partnership acquired such undistributed cash, along with all other assets of MarkWest, with the intent and obligation to distribute such cash to the Partnership's unitholders as part of the Partnership's fourth quarter 2015 distribution. In order to

effectively include the amount of Adjusted EBITDA and DCF generated by MarkWest during the fourth quarter of 2015 prior to the date of the MarkWest Merger, and effectively include such previously undistributed cash, we have made adjustments labeled “MarkWest’s pre-merger EBITDA” and “MarkWest undistributed DCF” in our reconciliations of Adjusted EBITDA and DCF to reported net income. MarkWest’s pre-merger EBITDA represents Adjusted EBITDA generated by MarkWest for the period from October 1, 2015 through December 3, 2015. MarkWest undistributed DCF represents the net adjustments made to MarkWest’s pre-merger EBITDA in order to arrive at the DCF generated by MarkWest for the period from October 1, 2015 through December 3, 2015.

The amount of Adjusted EBITDA and DCF generated by MarkWest for the period of October 1, 2015 through December 3, 2015 was considered by the board of directors of the Partnership’s general partner in approving the Partnership’s cash distribution for the fourth quarter of 2015. In addition, we believe the inclusion of the DCF generated by MarkWest for the period of October 1, 2015 through December 3, 2015 allows for a more meaningful calculation of the Partnership’s ratio of DCF generated to distributions declared for the fourth quarter of 2015. We believe the inclusion of these adjustments presents an appropriate basis for analyzing the complete operating results of the Partnership and MarkWest, on a combined basis, for the year ended December 31, 2015.

The following table presents a reconciliation of net operating margin to income from operations, the most directly comparable GAAP financial measure.

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation of net operating margin to income from operations:</b>			
Segment revenues	\$4,089	\$3,426	\$1,063
Purchased product costs	(651)	(448)	(20)
Total derivative loss (gain) related to purchased product costs	19	27	(5)
Other	1	(5)	—
<b>Net operating margin</b>	<u>3,458</u>	<u>3,000</u>	<u>1,038</u>
Revenue adjustment from unconsolidated affiliates <sup>(1)</sup>	(403)	(402)	(28)
Realized derivative loss related to purchased product costs <sup>(2)</sup>	(9)	(5)	—
Other	—	6	—
Unrealized derivative (loss) gains <sup>(2)</sup>	(6)	(36)	4
Income (loss) from equity method investments <sup>(3)</sup>	78	(74)	3
Other income	6	6	6
Other income—related parties	92	86	58
Cost of revenues (excludes items below)	(528)	(454)	(247)
Rental cost of sales	(62)	(57)	(11)
Rental cost of sales—related parties	(2)	(1)	(1)
Purchases—related parties	(455)	(388)	(172)
Depreciation and amortization	(683)	(591)	(129)
Impairment expense	—	(130)	—
General and administrative expenses	(241)	(227)	(125)
Other taxes	(54)	(50)	(15)
<b>Income from operations</b>	<u>\$1,191</u>	<u>\$ 683</u>	<u>\$ 381</u>

(1) These amounts relate to Partnership-operated unconsolidated affiliates. The chief operating decision maker and management include these to evaluate the segment performance as we continue to manage the operations. Therefore, the impact of the revenue is included for segment reporting purposes, but removed for GAAP purposes.

(2) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded



as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.

- (3) Includes an impairment expense of \$89 million related to one of the Partnership's equity method investments for the year ended December 31, 2016.

### **2017 Compared to 2016**

Service revenue increased \$198 million in 2017 compared to 2016. This variance was primarily due to a \$155 million increase in fees on higher volumes due to new gathering and processing facilities in the Marcellus and Southwest areas, a \$38 million increase from the acquisition of Ozark Pipeline, and an \$12 million increase related to volumes of crude oil and products shipped.

Service revenue-related parties increased \$146 million in 2017 compared to 2016. This increase was primarily related to a \$41 million increase related to volumes in related-party crude oil and products shipped, a \$26 million increase from the acquisition of Ozark Pipeline, and the inclusion of \$79 million of revenue generated by MPLXT and its subsidiaries in the first quarter of 2017, as they were not formed as a business until April 1, 2016.

Rental income decreased \$21 million in 2017 compared to 2016. This variance was primarily driven by the impact of recognizing rental income on a straight-line basis related to certain customer agreements.

Rental income-related parties increased \$44 million in 2017 compared to 2016. This increase was primarily related to the inclusion of \$24 million of revenue generated by MPLXT and its subsidiaries in the first quarter of 2017, as they were not formed as a business until April 1, 2016, and a \$14 million increase in HSM equipment revenue due to increased capacity as a result of acquisition or chartering of additional barges.

Product sales increased \$317 million in 2017 compared to 2016. This variance was due to mainly to increased pricing of approximately \$252 million as well as higher volume growth of approximately \$61 million in the Marcellus and Southwest areas.

Income (loss) from equity method investments increased \$152 million in 2017 compared to 2016. This variance was primarily due to the inclusion of \$15 million due to the acquisition of MarEn Bakken, \$21 million due the acquisition of the joint-interest assets from MPC, and \$27 million from our other equity method investments due mainly to increased volumes in the Utica area. The year ended December 31, 2016 also included an impairment expense of \$89 million related to one of our equity method investments.

Cost of revenues increased \$74 million in 2017 compared to 2016. This variance was primarily due to an increase of \$20 million due to the inclusion of MPLXT and its subsidiaries in the first quarter of 2017, as they were not formed as a business until April 1, 2016, an increase of \$31 million from the acquisition of the Ozark pipeline, an \$18 million increase in expenses related to greater project spend, and a \$4 million increase in HSM costs for chartering additional barges.

Purchased product costs increased \$203 million in 2017 compared to 2016. This variance was due to higher NGL and gas prices and purchase volumes in the Southwest area, offset by a \$12 million unrealized gain on an embedded derivative.

Purchases-related parties increased \$67 million in 2017 compared to 2016. The increase was primarily due to the inclusion of approximately \$23 million related party purchases of MPLXT and its subsidiaries in the first quarter of 2017, as they were not formed as a business until April 1, 2016, as well as general increases in employee costs due to headcount.

Depreciation and amortization expense increased \$92 million in 2017 compared to 2016. This variance was primarily due to accelerated depreciation expense of approximately \$38 million incurred on the decommissioning

of the Houston 1 facility in the Marcellus area and other various assets, approximately \$15 million of additional depreciation due to the inclusion of MPLXT and Ozark, as well as additions to in-service property, plant and equipment.

Impairment expense decreased \$130 million in 2017 compared to 2016. This variance was due to a non-cash impairment to goodwill in two reporting units in the G&P segment during 2016. See Item 8. Financial Statements and Supplementary Data—Note 18 for more information.

General and administrative expenses increased \$14 million in 2017 compared to 2016. The increase was primarily due to an increase in acquisition costs, as well as employee costs related to the omnibus and employee services agreements with MPC.

Interest expense and other financial costs increased \$92 million in 2017 compared to 2016. The increase was primarily due to the senior notes issued in February 2017.

### **2016 Compared to 2015**

Service revenue increased \$828 million in 2016 compared to 2015. This variance was primarily due to an \$824 million increase due to the MarkWest Merger, a \$3 million increase related to volumes of crude oil and products shipped and a \$1 million increase due to higher average tariffs received on the volumes of crude oil and products shipped.

Service revenue-related parties increased \$235 million in 2016 compared to 2015. This increase was primarily related to the acquisition of Predecessor, a \$13 million increase in higher average tariffs received on the volumes of crude oil and products shipped, a \$6 million increase related to volumes in related-party crude oil and products shipped, \$3 million increase in storage fees and increased HSM equipment revenue, partially offset by a reduction in fees previously paid by HSM on behalf of MPC that are now paid directly by MPC and a \$2 million decrease in revenue related to volume deficiency credits recognized.

Rental income increased \$278 million in 2016 compared to 2015. This variance was due to the MarkWest Merger.

Rental income-related parties increased \$89 million in 2016 compared to 2015. This increase was primarily related to the acquisition of Predecessor, a \$10 million increase in HSM equipment revenue and a \$3 million increase in storage fees.

Product sales increased \$536 million in 2016 compared to 2015. This variance was due to the MarkWest Merger.

Income (loss) from equity method investments decreased \$77 million in 2016 compared to 2015. This variance was primarily due to the MarkWest Merger combined with impairment charges of \$89 million related to one of our equity method investments.

Other income-related parties increased \$28 million in 2016 compared to 2015. The increase was due mainly to the MarkWest Merger and inclusion of management fee revenue for engineering and construction and administrative services for operating our unconsolidated joint ventures, offset by a decrease in fees paid to HSM by MPC.

Cost of revenues increased \$207 million in 2016 compared to 2015. This variance was primarily due to the MarkWest Merger and the acquisition of Predecessor, offset by a reduction in contract services and fees previously paid by HSM on behalf of MPC that are now paid directly by MPC.

Purchased product costs increased \$428 million in 2016 compared to 2015. This variance was due to the MarkWest Merger.

Rental cost of sales increased \$46 million in 2016 compared to 2015. This variance was primarily due to the MarkWest Merger.

Purchases-related parties increased \$216 million in 2016 compared to 2015. The increase was primarily due to the acquisition of Predecessor and higher compensation expenses provided under the omnibus and employee services agreements with MPC due to the MarkWest Merger, partially offset by increased capitalization of employee costs associated with capital projects.

Depreciation and amortization expense increased \$462 million in 2016 compared to 2015. This variance was primarily due to the depreciation of the fair value of the assets acquired in the MarkWest Merger and the acquisition of Predecessor.

Impairment expense increased \$130 million in 2016 compared to 2015. This variance was due to a non-cash impairment to goodwill in two reporting units in the G&P segment. See Item 8. Financial Statements and Supplementary Data—Note 18 for more information.

General and administrative expenses increased \$102 million in 2016 compared to 2015. The increase was primarily due to the MarkWest Merger and the acquisition of Predecessor, offset by a reduction in expenses due to changes in allocations provided for in the omnibus and employee services agreements with MPC as well as \$30 million of acquisition costs incurred in connection with the MarkWest Merger in 2015.

Other taxes increased \$35 million in 2016 compared to 2015. The increase was primarily due to property taxes related to the MarkWest Merger.

Interest expense and other financial costs increased \$214 million in 2016 compared to 2015. The increase was primarily due to the senior notes assumed as part of the MarkWest Merger.

## **SEGMENT REPORTING**

We classify our business in the following reportable segments: L&S and G&P. Segment operating income represents income from operations attributable to the reportable segments. We have investments in entities that we operate that are accounted for using equity method investment accounting standards. However, we view financial information as if those investments were consolidated. Corporate general and administrative expenses, unrealized derivative (losses) gains, property, plant and equipment impairment, goodwill impairment and depreciation and amortization are not allocated to the reportable segments. Management does not consider these items allocable to or controllable by any individual segment and, therefore, excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of income from operations attributable to the noncontrolling interests related to partially-owned entities that are either consolidated or accounted for as equity method investments. Segment operating income attributable to MPLX LP excludes the operating income related to the HSM Predecessor prior to the March 31, 2016 acquisition and the HST, WHC and MPLXT Predecessor prior to the March 1, 2017 acquisition.

The tables below present information about segment operating income for the reported segments for the years ended December 31, 2017, 2016 and 2015.

## L&S Segment

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Revenues and other income:</b>			
Segment revenues	\$1,480	\$1,241	\$913
Segment other income	<u>47</u>	<u>53</u>	<u>62</u>
Total segment revenues and other income	1,527	1,294	975
<b>Costs and expenses:</b>			
Segment cost of revenues	<u>692</u>	<u>552</u>	<u>416</u>
Segment operating income before portion attributable to noncontrolling interests and Predecessor	835	742	559
Segment portion attributable to noncontrolling interests and Predecessor	<u>53</u>	<u>289</u>	<u>237</u>
<b>Segment operating income attributable to MPLX LP</b>	<u>\$ 782</u>	<u>\$ 453</u>	<u>\$322</u>

### 2017 Compared to 2016

Segment revenue increased \$233 million primarily due to the inclusion of \$103 million of revenue generated by MPLXT and its subsidiaries in the first quarter of 2017, a \$46 million increase from higher crude and product transportation volumes, a \$64 million increase from the acquisition of the Ozark pipeline, and a \$14 million increase in HSM equipment revenue due to increased capacity as a result of acquisition or chartering of additional barges.

Segment cost of revenues increased \$140 million primarily due to the acquisitions of MPLXT and the Ozark pipeline, increased expenses related to greater project spend, salaries and compensation due to headcount, and other miscellaneous expenses.

Segment portion attributable to noncontrolling interests and Predecessor decreased \$236 million due to the inclusion of HSM for the first three months of 2016 and the acquisition of HST, WHC and MPLXT as of March 1, 2017.

### 2016 Compared to 2015

Segment revenue increased \$328 million primarily due to the acquisition of Predecessor as well as a \$14 million increase in higher average tariffs received on the volumes of crude oil and products shipped, \$9 million related to increased volumes of crude oil and products shipped, a \$6 million increase in storage income and increased HSM equipment revenue, partially offset by a reduction in fees previously paid by HSM on behalf of MPC that are now paid directly by MPC and a \$2 million decrease in revenue related to volume deficiency credits recognized.

Segment other income decreased \$9 million primarily due to a reduction in fees paid to HSM by MPC.

Segment cost of revenues increased \$136 million primarily due to the acquisition of Predecessor offset by a decrease in fees previously paid by HSM on behalf of MPC that are now being paid directly by MPC and a decrease in expenses related to the timing of maintenance projects.

Segment portion attributable to noncontrolling interests and Predecessor increased primarily due to the acquisition of Predecessor.

During 2017 and 2016, MPC did not ship its minimum committed volumes on certain of our pipelines. As a result, MPC was obligated to make \$45 million and \$56 million of deficiency payments in 2017 and 2016, respectively. We record deficiency payments as *Deferred revenue-related parties* on our Consolidated Balance Sheets. During 2017 and 2016, we recognized revenue of \$38 million and \$45 million, respectively, related to volume deficiency credits. At December 31, 2017 and 2016, the cumulative balance of *Deferred revenue-related parties* on our Consolidated Balance Sheets related to volume deficiencies was \$53 million and \$47 million, respectively. The following table presents the future expiration dates of the associated deferred revenue credits for 2017:

<i>(In millions)</i>	
March 31, 2018	\$ 11
June 30, 2018	10
September 30, 2018	10
December 31, 2018	11
March 31, 2019	4
June 30, 2019	3
September 30, 2019	4
December 31, 2019	—
Total	<u>\$ 53</u>

We will recognize revenue for the deficiency payments in future periods at the earlier of when volumes are transported in excess of the minimum quarterly volume commitments, when it becomes impossible to physically transport volumes necessary to utilize the accumulated credits or upon expiration of the make-up period. Deficiency payments are included in the determination of DCF in the period in which a deficiency occurs.

### **G&P Segment**

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Revenues and other income:</b>			
Segment revenues	\$2,609	\$2,185	\$150
Segment other income	<u>1</u>	<u>1</u>	<u>—</u>
Total segment revenues and other income	2,610	2,186	150
<b>Costs and expenses:</b>			
Segment cost of revenues	<u>1,105</u>	<u>907</u>	<u>62</u>
Segment operating income before portion attributable to noncontrolling interests	1,505	1,279	88
Segment portion attributable to noncontrolling interests	<u>170</u>	<u>147</u>	<u>12</u>
<b>Segment operating income attributable to MPLX LP</b>	<u>\$1,335</u>	<u>\$1,132</u>	<u>\$ 76</u>

### **2017 Compared to 2016**

Segment revenues increased \$424 million due to increased pricing on product sales of approximately \$207 million and increased volumes of \$61 million, combined with increased fees of approximately \$156 million on higher volumes due to new processing plants in the Marcellus and Southwest areas and additional fractionation capacity in the Marcellus and Utica areas.

Segment cost of revenues increased \$198 million due primarily to increased product costs resulting from higher prices of approximately \$144 million and higher volumes of \$47 million primarily in the Southwest area, as well as increased facility expenses.

Segment portion attributable to noncontrolling interests increased \$23 million primarily due to our joint venture, Sherwood Midstream, that was formed effective January 1, 2017, as well as growth within our other joint ventures that operate in the Utica area.

## 2016 Compared to 2015

The G&P segment increased overall due to the MarkWest Merger. There was no G&P segment prior to the MarkWest Merger.

## Segment Reconciliations

The following tables provide reconciliations of segment operating income to our consolidated income from operations, segment revenue to our consolidated total revenues and other income, and segment portion attributable to noncontrolling interests to our consolidated net income attributable to noncontrolling interests for the years ended December 31, 2017, 2016 and 2015. Adjustments related to unconsolidated affiliates relate to our Partnership-operated non-wholly-owned entities that we consolidate for segment purposes. Income (loss) from equity method investments relates to our portion of income (loss) from our unconsolidated joint ventures of which Partnership-operated joint ventures are consolidated for segment purposes. Other income-related parties consists of operational service fee revenues from our operated unconsolidated affiliates. Unrealized derivative activity is not allocated to segments.

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation to Income from operations:</b>			
L&S segment operating income attributable to MPLX LP	\$ 782	\$ 453	\$ 322
G&P segment operating income attributable to MPLX LP	1,335	1,132	76
Segment operating income attributable to MPLX LP	2,117	1,585	398
Segment portion attributable to unconsolidated affiliates	(178)	(173)	(8)
Segment portion attributable to Predecessor	53	289	236
Income (loss) from equity method investments <sup>(1)</sup>	78	(74)	3
Other income—related parties	51	40	2
Unrealized derivative (losses) gains <sup>(2)</sup>	(6)	(36)	4
Depreciation and amortization	(683)	(591)	(129)
Impairment expense	—	(130)	—
General and administrative expenses	(241)	(227)	(125)
<b>Income from operations</b>	<u>\$1,191</u>	<u>\$ 683</u>	<u>\$ 381</u>

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation to Total revenues and other income:</b>			
Total segment revenues and other income	\$4,137	\$3,480	\$1,125
Revenue adjustment from unconsolidated affiliates	(403)	(402)	(28)
Income (loss) from equity method investments <sup>(1)</sup>	78	(74)	3
Other income—related parties	51	40	2
Unrealized derivative gains (losses) related to product sales <sup>(2)</sup>	4	(15)	(1)
<b>Total revenues and other income</b>	<u>\$3,867</u>	<u>\$3,029</u>	<u>\$1,101</u>

<i>(in millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation to Net income attributable to noncontrolling interests and Predecessor:</b>			
Segment portion attributable to noncontrolling interests and Predecessor	\$ 223	\$ 436	\$249
Portion of noncontrolling interests and Predecessor related to items below segment income from operations	(106)	(203)	(67)
Portion of operating income attributable to noncontrolling interests of unconsolidated affiliates	<u>(75)</u>	<u>(32)</u>	<u>(5)</u>
<b>Net income attributable to noncontrolling interests and Predecessor</b>	<u>\$ 42</u>	<u>\$ 201</u>	<u>\$177</u>

- (1) Includes an impairment expense of \$89 million related to one of the Partnership's equity method investments for the year ended December 31, 2016.
- (2) The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.

## LIQUIDITY AND CAPITAL RESOURCES

### Cash Flows

Our cash and cash equivalents balance was \$5 million at December 31, 2017, compared to \$234 million at December 31, 2016. The change in cash and cash equivalents was due to the factors discussed below. Net cash provided by (used in) operating activities, investing activities and financing activities for the past three years were as follows:

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Net cash provided by (used in):			
Operating activities	\$ 1,907	\$ 1,491	\$ 427
Investing activities	(2,307)	(1,413)	(1,686)
Financing activities	<u>171</u>	<u>113</u>	<u>1,275</u>
Total	<u>\$ (229)</u>	<u>\$ 191</u>	<u>\$ 16</u>

**Cash Flows Provided by Operating Activities.** Net cash provided by operating activities increased \$416 million in 2017 compared to 2016, the majority of which is related to an increase in net income net of non-cash adjustments of approximately \$240 million. This favorable change was driven primarily by higher prices and volumes, as well as the inclusion of MPLXT, since it was not formed as a business until April 1, 2016, and the acquisition of the Ozark pipeline. In addition, there was an increase in distributions received from unconsolidated affiliates of \$93 million due primarily to the acquisition of an equity interest in MarEn Bakken and the Joint-Interest Acquisition from MPC. Working capital reflected favorable changes of approximately \$83 million compared to 2016.

Net cash provided by operating activities increased \$1.1 billion in 2016 compared to 2015 due primarily to due to the MarkWest Merger.

**Cash Flows Used in Investing Activities.** Net cash used in investing activities increased \$894 million in 2017 compared to 2016, primarily due to the acquisition of an equity interest in MarEn Bakken for \$513 million, investments in other unconsolidated entities of approximately \$248 million, \$219 million for the acquisition of the Ozark pipeline, \$33 million for the buy-out of an equity method investment partner, and an increase in cash used for additions to property, plant and equipment related to various capital projects. Partially offsetting these items was a net increase of \$97 million in investment loans with MPC and a return of capital of \$26 million from our acquisition of equity interests in Sherwood Midstream and Sherwood Midstream Holdings.

Net cash used in investing activities decreased \$273 million in 2016 compared to 2015, primarily due to a \$979 million use of cash for additions to property, plant and equipment and a \$73 million use of cash for investments in unconsolidated affiliates, offset by a \$1.2 billion decrease in acquisitions due to the MarkWest Merger and \$101 million source of cash from investment loans between HSM and related parties prior to the HSM acquisition.

**Cash Flows from Financing Activities.** Net cash provided by financing activities in 2017 was \$171 million compared to \$113 million in 2016. The sources of cash in 2017 was primarily due to \$2.2 billion of net proceeds from the senior notes issued in February 2017, \$670 million of proceeds under the bank revolving credit facility, \$129 million in contributions from noncontrolling interests, and \$483 million of net proceeds from sales of common units under the ATM Program. These items were partially offset by distributions to MPC of \$1.9 billion for the acquisition of HST, WHC and MPLXT and the Joint-interest Acquisition, \$250 million repayment of the term loan facility, \$165 million repayment of the bank revolving credit facility, distributions of \$65 million to Preferred unitholders, and increased distributions of \$1.1 billion to unitholders and our general partner due mainly to the increase in units outstanding, as well as a 12.1 percent increase in the distribution per limited partner unit.

The sources of cash in 2016 primarily consisted of \$984 million in net proceeds from the issuance of Preferred units and \$792 million of net cash proceeds from the issuance of common units and general partner units, as well as contributions of \$225 million from MPC as part of the Class A Reorganization. The uses of cash in 2016 primarily consisted of net repayments of long-term debt and distributions to unitholders.

The sources of cash in 2015 primarily consisted of contributions of \$1.2 billion from MPC for the MarkWest Merger and proceeds of \$169 million from issuances of general partner units. The uses of cash in 2015 primarily consisted of distributions to unitholders.

Long-term debt borrowings and repayments were a net \$2.5 billion source of cash in 2017 compared to an \$878 million use of cash in 2016 and a \$38 million source of cash in 2015. During 2017, we used proceeds from the issuance of the February 2017 senior notes and the bank revolving credit facility for general partnership purposes, including the acquisitions of HST, WHC, MPLXT and the Joint-Interest Acquisition from MPC, the acquisition of our equity interest in MarEn Bakken, the acquisition of the Ozark pipeline and capital expenditures. During 2016, we used proceeds from the issuance of Preferred units to repay amounts outstanding under the bank revolving credit facility. During 2015, we used proceeds from the issuance of \$500 million aggregate of principal amount of senior notes to repay \$385 million outstanding under the bank revolving credit facility. See Item 8. Financial Statements and Supplemental Data—Note 17 for additional information on our long-term debt.

### **Debt and Liquidity Overview**

On November 20, 2014, we entered into a credit agreement with a syndicate of lenders which provided for a five-year, \$1 billion bank revolving credit facility and a \$250 million term loan facility. The term loan facility was drawn in full on November 20, 2014. In connection with the MarkWest Merger, the aggregate capacity of the credit facility was extended to \$2 billion and the maturity date was extended to December 4, 2020. On July 21, 2017, we replaced the previously existing revolving credit facility with a \$2.25 billion five-year bank revolving credit facility that expires in July 2022 (“MPLX Credit Agreement”). The financial covenants and the interest rate terms contained in the new credit agreement are substantially the same as those contained in the previous bank revolving credit facility. Additionally, on July 19, 2017, we prepaid the entire outstanding principal amount of the \$250 million term loan facility with cash on hand and terminated the agreement.

The MPLX Credit Agreement includes letter of credit issuing capacity of up to \$222 million and swingline capacity of up to \$100 million. The borrowing capacity under the MPLX Credit Agreement may be increased by up to an additional \$500 million, subject to certain conditions, including the consent of lenders whose



commitments would increase. In addition, the maturity date may be extended for up to two additional one-year periods subject to, among other conditions, the approval of lenders holding the majority of the commitments then outstanding, provided that the commitments of any non-consenting lenders will terminate on the then-effective maturity date. During 2017, we borrowed \$670 million under the MPLX Credit Agreement, at an average interest rate of 2.748 percent, and repaid \$165 million of these borrowings. At December 31, 2017, we had \$505 million borrowings and \$3 million in letters of credit outstanding under this facility, resulting in total unused loan availability of approximately \$1.7 billion, or 77.4 percent, of the borrowing capacity. There were no borrowings under the previous bank revolving credit facility between January 1, 2017 and July 21, 2017.

Borrowings under the MPLX Credit Agreement bear interest at either the Adjusted LIBOR or the Alternate Base Rate (as defined in the MPLX Credit Agreement), at our election, plus a specified margin. We are charged various fees and expenses in connection with the agreement, including administrative agent fees, commitment fees on the unused portion of the bank revolving credit facility and fees with respect to issued and outstanding letters of credit. The applicable margins to the benchmark interest rates and certain of the fees fluctuate based on the credit ratings in effect from time to time on our long-term debt.

The MPLX Credit Agreement contains certain representations and warranties, affirmative and negative covenants and events of default that we consider usual and customary for an agreement of that type and that could, among other things, limit our ability to pay distributions to our unitholders. The financial covenant requires us to maintain a ratio of Consolidated Total Debt as of the end of each fiscal quarter to Consolidated EBITDA (both as defined in the MPLX Credit Agreement) for the prior four fiscal quarters of no greater than 5.0 to 1.0 (or 5.5 to 1.0 for up to two fiscal quarters following certain acquisitions). Consolidated EBITDA is subject to adjustments for certain acquisitions completed and capital projects undertaken during the relevant period. Other covenants restrict us and/or certain of our subsidiaries from incurring debt, creating liens on our assets and entering into transactions with affiliates. As of December 31, 2017, we were in compliance with this financial covenant with a ratio of Consolidated Total Debt to Consolidated EBITDA of 3.2 to 1.0, as well as all other covenants contained in the MPLX Credit Agreement.

As of December 31, 2017, we had \$6.9 billion in aggregate principal amount of senior notes outstanding. The increase as of December 31, 2017 compared to year-end 2016 resulted from the February 2017 public offering of senior notes. As of December 31, 2017, there were no minimum principal payments due during the next five years. For further discussion, see Item 8. Financial Statements and Supplementary Data—Note 17.

On February 1, 2018, in connection with the dropdown acquisition, the Partnership drew \$4.1 billion on a 364-day term loan facility with a syndicate of lenders. The proceeds of the term loan facility were used to fund the cash portion of the dropdown consideration.

On February 8, 2018, the Partnership issued in a public offering of \$5.5 billion senior notes, consisting of \$500 million aggregate principal amount of 3.375 percent unsecured senior notes due March 2023, \$1.25 billion aggregate principal amount of 4.0 percent unsecured senior notes due March 2028, \$1.75 billion aggregate principal amount of 4.5 percent unsecured senior notes due April 2038, \$1.5 billion aggregate principal amount of 4.7 percent unsecured senior notes due April 2048, and \$500 million aggregate principal amount of 4.9 percent unsecured senior notes due April 2058. The notes were offered at a price to the public of 99.931 percent, 99.551 percent, 98.811 percent, 99.348 percent, and 99.289 percent of par, respectively. The net proceeds were used to repay the 364-day term loan facility of \$4.1 billion, the outstanding borrowings under the MPLX Credit Agreement and the intercompany loan agreement with MPC Investment, as well as for general partnership purposes.

Our intention is to maintain an investment grade credit profile. As of January 31, 2018, the credit ratings on our senior unsecured debt were at or above investment grade level as follows:

<u>Rating Agency</u>	<u>Rating</u>
Moody's	Baa3 (stable outlook)
Fitch	BBB- (stable outlook)
Standard & Poor's	BBB (stable outlook)

The ratings shown above reflect the respective views of the rating agencies. Although it is our intention to maintain a credit profile that supports an investment grade rating, there is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant.

The MPLX Credit Agreement does not contain credit rating triggers that would result in the acceleration of interest, principal or other payments in the event that our credit ratings are downgraded. However, any downgrades in the credit ratings of our senior unsecured debt ratings to below investment grade ratings would increase the applicable interest rates and other fees payable under the MPLX Credit Agreement and may limit our flexibility to obtain future financing.

Our liquidity totaled \$1.9 billion at December 31, 2017, consisting of:

<i>(In millions)</i>	December 31, 2017		
	<u>Total Capacity</u>	<u>Outstanding Borrowings</u>	<u>Available Capacity</u>
MPLX LP—bank revolving credit facility expiring 2022 <sup>(1)</sup>	\$2,250	\$(508)	\$1,742
MPC Investment—loan agreement	500	(386)	114
Total	<u>\$2,750</u>	<u>\$(894)</u>	<u>\$1,856</u>
Cash and cash equivalents			<u>5</u>
Total liquidity			<u>\$1,861</u>

<sup>(1)</sup> Outstanding borrowings include \$3 million in letters of credit outstanding under this facility.

We expect our ongoing sources of liquidity to include cash generated from operations and borrowings under our revolving credit facilities. We believe that cash generated from these sources will be sufficient to meet our short term and long term funding requirements, including working capital requirements, capital expenditure requirements, acquisitions, contractual obligations, and quarterly cash distributions.

MPC manages our cash and cash equivalents on our behalf directly with third-party institutions as part of the treasury services that it provides to us under our omnibus agreement. From time to time, we may also consider utilizing other sources of liquidity, including the formation of joint ventures or sales of non-strategic assets.

## Equity and Preferred Units Overview

The following table summarizes the changes in the number of units outstanding through December 31, 2017:

<i>(In units)</i>	Common	Class B	Subordinated	General Partner	Total
<b>Balance at December 31, 2014</b>	43,341,098	—	36,951,515	1,638,625	81,931,238
Unit-based compensation awards	18,932	—	—	386	19,318
Issuance of units under the ATM Program	25,166	—	—	514	25,680
Subordinated unit conversion	36,951,515	—	(36,951,515)	—	—
MarkWest Merger	216,350,465	7,981,756	—	5,160,950	229,493,171
<b>Balance at December 31, 2015</b>	296,687,176	7,981,756	—	6,800,475	311,469,407
Unit-based compensation awards	120,989	—	—	2,470	123,459
Issuance of units under the ATM Program	26,347,887	—	—	537,710	26,885,597
Contribution of HSM	22,534,002	—	—	459,878	22,993,880
Class B conversion	4,350,057	(3,990,878)	—	7,330	366,509
Class A Reorganization	7,153,177	—	—	(436,758)	6,716,419
<b>Balance at December 31, 2016</b>	357,193,288	3,990,878	—	7,371,105	368,555,271
Unit-based compensation awards	268,167	—	—	5,472	273,639
Issuance of units under the ATM Program	13,846,998	—	—	282,591	14,129,589
Contribution of HST/WHC/MPLXT	12,960,376	—	—	264,497	13,224,873
Contribution of the Joint-interest Acquisition	18,511,134	—	—	377,778	18,888,912
Class B conversion	4,350,057	(3,990,878)	—	7,330	366,509
<b>Balance at December 31, 2017</b>	<u>407,130,020</u>	<u>—</u>	<u>—</u>	<u>8,308,773</u>	<u>415,438,793</u>

For more details on equity activity, see Item 8. Financial Statements and Supplementary Data—Notes 8 and 9.

On May 13, 2016, the Partnership completed the private placement of approximately 30.8 million Preferred units for a cash purchase price of \$32.50 per unit. The aggregate net proceeds of approximately \$984 million from the sale of the Preferred units were used for capital expenditures, repayment of debt and general partnership purposes.

The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to \$0.528125 per unit commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will be entitled to receive as a quarterly distribution the greater of \$0.528125 per unit or the amount of per unit distributions paid to common units. Since the Preferred unit distribution was declared subsequent to the end of the second quarter of 2016, the distribution was not accrued to the Preferred unit holders' capital account. For the quarter ended June 30, 2016, the Preferred units received an earned aggregate cash distribution of \$9 million, based on the quarterly per unit distribution prorated for the 49-day period the Preferred units were outstanding during the second quarter of 2016. Distributions paid to Preferred unit holders for the years ended December 31, 2017 and 2016, were \$65 million and \$25 million, respectively.

On July 1, 2016, 3,990,878 Class B units automatically converted into 1.09 MPLX LP common units and the right to receive \$6.20 per unit in cash. They also received the second quarter 2016 distribution. MPC funded the \$6.20 per unit cash payment, which reduced our liability payable to Class B unitholders by approximately

\$25 million on July 1, 2016. As a result of the Class B conversion on July 1, 2016, MPLX GP contributed less than \$1 million in exchange for 7,330 general partner units to maintain its two percent general partner interest. On July 1, 2017, all of the remaining 3,990,878 Class B units automatically converted into 1.09 MPLX LP common units and the right to receive \$6.20 per unit in cash. MPC funded this cash payment, which reduced our liability payable to Class B unitholders by approximately \$25 million on July 1, 2017. As a result of the Class B units conversion on July 1, 2017, MPLX GP contributed less than \$1 million in exchange for 7,330 general partner units to maintain its two percent general partner interest. As common units outstanding as of the August 7, 2017 record date, the converted Class B units participated in the second quarter 2017 distribution.

On August 4, 2016, the Partnership entered into a second amended and restated distribution agreement providing for the at-the-market issuances of common units, in amounts, at prices and on terms determined by market conditions and other factors at the time of the offerings. During the year ended December 31, 2017, the sale of common units under the ATM Program generated net proceeds of approximately \$473 million, all of which transactions were executed during the first half of the year. The Partnership used the net proceeds from sales under the ATM Program for general partnership purposes, including repayment or refinancing of debt and funding for acquisitions, working capital requirements and capital expenditures.

On September 1, 2016, the Partnership and various affiliates initiated a series of reorganization transactions in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements. In connection with these transactions, all issued and outstanding MPLX LP Class A units were either distributed to or purchased by MPC in exchange for \$84 million in cash, 21,401,137 MPLX LP common units and 436,758 MPLX LP general partner units. MPC also contributed \$141 million to facilitate the repayment of intercompany debt between MarkWest Hydrocarbon and MarkWest. As a result of these transactions, the MPLX LP Class A units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership. See additional discussion in Item 8. Financial Statements and Supplementary Data—Notes 8 and 12.

We intend to pay a minimum quarterly distribution of \$0.2625 per unit, which equates to \$109 million per quarter, or \$436 million per year, based on the number of common and general partner units. On January 26, 2018, we announced that the board of directors of our general partner had declared a distribution of \$0.6075 per common unit that was paid on February 14, 2018 to common unitholders of record on February 5, 2018. This represents a 17 percent increase over the fourth quarter 2016 distribution. We have provided distribution growth guidance of 10 percent for 2018. This increase in the distribution is consistent with our intent to maintain an attractive distribution growth profile over the long term. Although our Partnership Agreement requires that we distribute all of our available cash each quarter, we do not otherwise have a legal obligation to distribute any particular amount per common unit.

MPC agreed to waive the fourth quarter 2017 distributions on the common units issued in connection with the acquisition of Refining Logistics and Fuels Distribution which took place on February 1, 2018. MPC also agreed to waive the portion of the fourth quarter 2017 distributions on common units received on February 1, 2018 in the GP IDR Exchange in excess of what would have been distributable to MPC for its economic GP interest, including IDRs, absent the exchange. Together, the value of these waived distributions was \$135 million. Additionally, in connection with our acquisition of a partial, indirect equity interest in the Bakken Pipeline system on February 15, 2017, MPC agreed to waive its right to receive incentive distributions of \$1.6 million per quarter for twelve consecutive quarters beginning with the distributions declared in the first quarter of 2017 and paid to MPC in the second quarter of 2017, which was prorated from the acquisition date. This waiver is no longer applicable as a result of the GP IDR Exchange on February 1, 2018.

The allocation of total quarterly cash distributions to general and limited partners is as follows for the years ended December 31, 2017, 2016 and 2015. Our distributions are declared subsequent to quarter end; therefore, the following table represents total cash distributions applicable to the period in which the distributions were earned. See additional discussion in Item 8. Financial Statements and Supplementary Data—Note 7.

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Distribution declared:</b>			
Limited partner units—public	\$ 656	\$ 533	\$ 151
Limited partner units—MPC	210	159	104
Limited partner units—GP	128	—	—
General partner units—MPC	18	18	6
IDRs—MPC	211	187	54
Total GP & LP distribution declared	<u>1,223</u>	<u>897</u>	<u>315</u>
Redeemable preferred units	<u>65</u>	<u>41</u>	<u>—</u>
Total distribution declared	<u>\$ 1,288</u>	<u>\$ 938</u>	<u>\$ 315</u>
<b>Cash distributions declared per limited partner common unit:</b>			
Quarter ended March 31,	\$0.5400	\$0.5050	\$0.4100
Quarter ended June 30,	0.5625	0.5100	0.4400
Quarter ended September 30,	0.5875	0.5150	0.4700
Quarter ended December 31,	<u>0.6075</u>	<u>0.5200</u>	<u>0.5000</u>
Year ended December 31,	<u>\$2.2975</u>	<u>\$2.0500</u>	<u>\$1.8200</u>

### Capital Expenditures

Our operations are capital intensive, requiring investments to expand, upgrade, enhance or maintain existing operations and to meet environmental and operational regulations. Our capital requirements consist of maintenance capital expenditures and growth capital expenditures. Examples of maintenance capital expenditures are those made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. In contrast, growth capital expenditures are those incurred for acquisitions or capital improvements that we expect will increase our operating capacity to increase volumes gathered, processed, transported or fractionated, decrease operating expenses within our facilities or increase operating income over the long term. Examples of growth capital expenditures include the acquisition of equipment or the construction costs associated with new well connections, and the development or acquisition of additional pipeline, processing or storage capacity. In general, growth capital includes costs that are expected to generate additional or new cash flow for the Partnership.

Our capital expenditures for the past three years are shown in the table below:

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Capital expenditures<sup>(1)</sup>:</b>			
Maintenance	\$ 103	\$ 84	\$ 51
Expansion	<u>1,381</u>	<u>1,213</u>	<u>311</u>
<b>Total capital expenditures</b>	1,484	1,297	362
Less: Increase (decrease) in capital accruals	71	(22)	27
Asset retirement expenditures	<u>2</u>	<u>6</u>	<u>1</u>
<b>Additions to property, plant and equipment</b>	1,411	1,313	334
Capital expenditures of unconsolidated subsidiaries <sup>(2)</sup>	<u>384</u>	<u>131</u>	<u>24</u>
<b>Total gross capital expenditures</b>	1,795	1,444	358
Less: Joint venture partner contributions	<u>169</u>	<u>64</u>	<u>8</u>
<b>Total capital expenditures, net</b>	1,626	1,380	350
Less: Maintenance capital expenditures	<u>108</u>	<u>88</u>	<u>51</u>
<b>Total growth capital expenditures</b>	1,518	1,292	299
Acquisition, net of cash acquired	<u>—</u>	<u>—</u>	<u>1,218</u>
<b>Total growth capital expenditures and acquisition</b>	<u>\$1,518</u>	<u>\$1,292</u>	<u>\$1,517</u>

(1) Includes capital expenditures of the Predecessor for all periods presented.

(2) Includes amounts related to unconsolidated, Partnership-operated subsidiaries.

Our growth capital plan for 2018 is \$2.2 billion, not including the February 1, 2018 dropdown transaction with MPC as discussed below and in Item 8. Financial Statements and Supplementary Data—Note 24, or its respective subsequent capital spending. The G&P segment capital plan includes the addition of 1.5 billion bcf/d processing capacity at eight gas processing plants, six in the Marcellus and Utica basins and two in the Southwest, which expands the Partnership's processing capacity in the Permian basin and the STACK shale play of Oklahoma. The G&P segment capital plan also includes the addition of 100,000 barrels per day of fractionation capacity in the Marcellus and Utica basins. In the L&S segment, work continues on the expansion of the Ozark and Wood River-to Patoka pipeline systems, both of which are targeted for completion in mid-2018. The L&S capital plan also includes the completion of a butane cavern in Robinson, Illinois, tank expansions in Patoka, Illinois, and Texas City, Texas, and an expansion of the Partnership's marine fleet. We also have large organic growth prospects associated with the anticipated growth of MPC's operations and third-party activity in our areas of operation that we anticipate will provide attractive returns and cash flows. We continuously evaluate our capital plan and make changes as conditions warrant.

## Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2017:

<i>(In millions)</i>	Total	2018	2019 & 2020	2021 & 2022	Thereafter
Bank revolving credit facility <sup>(1)</sup>	\$ 591	\$ 19	\$ 38	\$ 534	\$ —
Intercompany loan	419	11	408	—	—
Long-term debt <sup>(1)</sup>	10,352	324	649	649	8,730
Capital lease obligations	8	1	7	—	—
Operating leases <sup>(2)</sup>	249	54	79	62	54
Purchase obligations:					
Contracts to acquire property, plant & equipment	355	354	1	—	—
Other contracts	59	28	15	9	7
Total purchase obligations <sup>(3)</sup>	414	382	16	9	7
Natural gas purchase obligations <sup>(4)</sup>	91	20	36	35	—
SMR liability <sup>(5)</sup>	211	17	34	34	126
Transportation and terminalling <sup>(6)</sup>	573	52	123	123	275
Other long-term liabilities reflected on the Consolidated Balance Sheets:					
Other liabilities	2	—	2	—	—
AROs <sup>(7)</sup>	28	—	—	—	28
Total contractual cash obligations	<u>\$12,938</u>	<u>\$880</u>	<u>\$1,392</u>	<u>\$1,446</u>	<u>\$9,220</u>

(1) Amounts represent outstanding borrowings at December 31, 2017, plus any commitment and administrative fees and interest.

(2) Amounts relate primarily to our office, railcar, and vehicle leases.

(3) Represents purchase orders and contracts related to the purchase or build out of property, plant and equipment. Purchase obligations exclude current and long-term unrealized losses on derivative instruments included on the accompanying Consolidated Balance Sheets, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts are generally 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.

(4) Natural gas purchase obligations consist primarily of a purchase agreement with a producer in our Southern Appalachia Operations. The contract provides for the purchase of keep-whole volumes at a specific price and is a component of a broader regional arrangement. The contract price is designed to share a portion of the frac spread with the producer and as a result, the amounts reflected for the obligation exceed the cost of purchasing the keep-whole volumes at a market price. The contract is considered an embedded derivative (see Item 8. Financial Statements and Supplementary Data—Note 16 for the fair value of the frac spread sharing component). We use the estimated future frac spreads as of December 31, 2017 for calculating this obligation. The counterparty to the contract has the option to renew the gas purchase agreement and the related keep-whole processing agreement for two successive five-year terms after 2022, which is not included in the natural gas purchase obligations line item.

(5) Represents amounts due under a product supply agreement (see Item 8. Financial Statements and Supplementary Data—Note 23 for further discussion of the product supply agreement).

(6) Represents transportation and terminalling agreements that obligate us to minimum volume, throughput or payment commitments over the terms of the agreements, which will range from three to ten years. We expect to pass any minimum payment commitments through to producer customers. Minimum fees due under transportation agreements do not include potential fee increases as required by FERC.

(7) Excludes estimated accretion expense of \$28 million. The total amount to be paid is approximately \$56 million.

In addition to the obligations included in the table above, we have an omnibus agreement and employee services agreements with MPC. The omnibus agreement with MPC addresses our payment of a fixed annual fee to MPC for the provision of executive management services by certain executive officers of our general partner and our reimbursement to MPC for the provision of certain general and administrative services to us. The omnibus agreement remains in full force and effect as long as MPC controls our general partner. Under the omnibus agreement, we paid to MPC in equal monthly installments an annual amount of approximately \$69 million in 2017 for the provision of services by MPC, such as information technology, engineering, legal, accounting, treasury, human resources and other administrative services. The annual amount includes a fixed annual fee of approximately \$10 million for the provision of certain executive management services by certain officers of our general partner.

We also pay MPC additional amounts based on the costs actually incurred by MPC in providing other services, except for the portion of the amount attributable to engineering services, which is based on the amounts actually incurred by MPC and its affiliates plus six percent of such costs. In addition, we are obligated to reimburse MPC for most out-of-pocket costs and expenses incurred by MPC on our behalf.

The Partnership has various employee services agreements with MPC under which the Partnership reimburses MPC for employee benefit expenses, along with the provision of operational and management services in support of both our L&S and G&P segments' operations, including those in support of HST, WHC, MPLXT and HSM. We incurred \$513 million of expenses under the employee services agreements for 2017.

#### **Off-Balance Sheet Arrangements**

As of December 31, 2017, we have not entered into any transactions, agreements or other arrangements that would result in off-balance sheet liabilities.

#### **Forward-looking Statements**

Our opinions concerning liquidity and capital resources and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors, including cash provided by operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and future credit ratings by rating agencies. The discussion of liquidity and capital resources above also contains forward-looking statements regarding expected capital spending. The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include negative capital market conditions, including an increase of the current yield on common units, adversely affecting the Partnership's ability to meet its distribution growth guidance; our ability to achieve the strategic and other objectives discussed herein and other proposed transactions; adverse changes in laws including with respect to tax and regulatory matters; the adequacy of the Partnership's capital resources and liquidity, including, but not limited to, availability of sufficient cash flow to pay distributions and access to debt on commercially reasonable terms, and the ability to successfully execute its business plans and growth strategy; the timing and extent of changes in commodity prices and demand for crude oil, refined products, feedstocks or other hydrocarbon-based products; continued/further volatility in and/or degradation of market and industry conditions; changes to the expected construction costs and timing of projects; completion of midstream infrastructure by competitors; disruptions due to equipment interruption or failure, including electrical shortages and power grid failures; the suspension, reduction or termination of MPC's obligations under the Partnership's commercial agreements; modifications to earnings and distribution growth objectives; our ability to manage



disruptions in credit markets or changes to our credit rating; compliance with federal and state environmental, economic, health and safety, energy and other policies and regulations and/or enforcement actions initiated thereunder; adverse results in litigation; changes to the Partnership's capital budget; prices of and demand for natural gas, NGLs, crude oil and refined products, delays in obtaining necessary third-party approvals and governmental permits, changes in labor, material and equipment costs and availability, planned and unplanned outages, the delay of, cancellation of or failure to implement planned capital projects, project overruns, disruptions or interruptions of our operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations. These factors, among others, could cause actual results to differ materially from those set forth in the forward-looking statements. For additional information on forward-looking statements and risks that can affect our business, see "Disclosures Regarding Forward-Looking Statements" and Item 1A. Risk Factors in this Annual Report on Form 10-K.

### **Effects of Inflation**

Inflation did not have a material impact on our results of operations for the years ended December 31, 2017, 2016 or 2015. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire, build or replace property, plant and equipment. It may also increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and expect to continue to pass along all or a portion of increased costs to our customers in the form of higher fees.

### **TRANSACTIONS WITH RELATED PARTIES**

As of December 31, 2017, MPC owned our general partner, an approximate 28.4 percent limited partner interest in us, and all of our incentive distribution rights.

Excluding revenues attributable to volumes shipped by MPC under joint tariffs with third parties that are treated as third-party revenues for accounting purposes, MPC accounted for 36 percent, 41 percent and 82 percent of our total revenues and other income for 2017, 2016 and 2015, respectively. We provide crude oil and product pipeline transportation services based on regulated tariff rates and storage services and inland marine transportation based on contracted rates.

Of our total costs and expenses, MPC accounted for 22 percent, 23 percent and 34 percent for 2017, 2016 and 2015, respectively. MPC performed certain services for us related to information technology, engineering, legal, accounting, treasury, human resources and other administrative services.

We believe that transactions with related parties were conducted under terms comparable to those with unrelated parties. For further discussion of agreements and activity with MPC and related parties see Item 1. Business—Our Transportation and Storage Services Agreements with MPC,—Operating and Management Services Agreements with MPC and Third Parties,—Other Agreements with MPC and Item 8. Financial Statements and Supplementary Data—Note 6.

### **ENVIRONMENTAL MATTERS AND COMPLIANCE COSTS**

We are subject to extensive federal, state and local environmental laws and regulations. These laws, which change frequently, regulate the discharge of materials into the environment or otherwise relate to protection of the environment. Compliance with these laws and regulations may require us to remediate environmental damage from any discharge of hazardous, petroleum or chemical substances from our facilities or require us to install additional pollution control equipment on our equipment and facilities. Our failure to comply with these or any other environmental or safety-related regulations could result in the assessment of administrative, civil or criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may subject us to additional operational constraints.

Future expenditures may be required to comply with the Clean Air Act and other federal, state and local requirements for our various facilities. The impact of these legislative and regulatory developments, if enacted or adopted, could result in increased compliance costs and additional operating restrictions on our business, each of which could have an adverse impact on our financial position, results of operations and liquidity. MPC will indemnify us for certain of these costs under the omnibus agreement.

If these expenditures, as with all costs, are not ultimately reflected in the fees and tariff rates we receive for our services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including, but not limited to, the age and location of its operating facilities. Our environmental expenditures for each of the past three years were:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Capital	\$ 5	\$ 12	\$ 5
Percent of total capital expenditures	0%	1%	1%
Compliance:			
Operating and maintenance	\$26	\$ 95	\$37
Remediation <sup>(1)</sup>	<u>4</u>	<u>10</u>	<u>10</u>
Total	<u>\$30</u>	<u>\$105</u>	<u>\$47</u>

<sup>(1)</sup> These amounts include spending charged against remediation reserves, where permissible, but exclude non-cash accruals for environmental remediation.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We believe we comply with all legal requirements regarding the environment, but since not all of them are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

Our environmental capital expenditures are expected to approximate \$13 million in 2018. Actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed. The amount of expenditures in 2018 is also dependent upon the resolution of the matters described in Item 3—Legal Proceedings, which may require us to complete additional projects and increase our actual environmental capital and operating expenditures.

## **CRITICAL ACCOUNTING ESTIMATES**

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See Item 8 Financial Statements and Supplementary Data—Note 2 for additional information on these policies and estimates, as well as a discussion of additional accounting policies and estimates.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<i>Acquisitions</i>		
<p>In accounting for business combinations, acquired assets and liabilities, noncontrolling interests, if any, and any contingent consideration are recorded based on estimated fair values as of the date of acquisition. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence. Valuation techniques that maximize the use of observable inputs are favored.</p>	<p>The fair value of assets, liabilities, including contingent consideration, and noncontrolling interests as of the acquisition date are often estimated using a combination of approaches, including the income approach, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate; the cost approach, which requires estimates of replacement costs and useful life and obsolescence estimates; and the market approach which uses market data and adjusts for entity-specific differences. Additionally, for customer contract intangibles we must estimate the expected life of the relationship with our customers on a reporting unit basis. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.</p>	<p>If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets, liabilities and noncontrolling interests significantly differed from assumptions made, the allocation of purchase price between goodwill, intangibles, noncontrolling interests, equity method investments and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise. Further, if customer relationships terminate prior to the expected useful life, we will be required to record a charge to operations to write-off any remaining unamortized balance of the intangible asset assigned to that customer.</p>
<p>The excess or shortfall of the purchase price when compared to the fair value of the net tangible and identifiable intangible assets acquired, if any, and noncontrolling interests, if any, is recorded as goodwill or a bargain purchase gain,</p>		<p>See Item 8. Financial Statements and Supplementary Data—Note 4 for additional information on the Ozark pipeline acquisition completed March 1, 2017, and the MarkWest Merger that was completed effective December 4, 2015.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p>respectively. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment, intangible assets, equity method investments, contingent consideration, other assets and liabilities and noncontrolling interests. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired, liabilities assumed, and noncontrolling interests, if any.</p>		
<p><i>Impairment of Long-Lived Assets</i></p>		
<p>Management evaluates our long-lived assets, including intangibles, for impairment when certain events have taken place that indicate that the carrying value may not be recoverable from the expected undiscounted future cash flows. Qualitative and quantitative information is reviewed in order to determine if a triggering event has occurred or if an impairment indicator exists. If we determine that a triggering event has occurred we would complete a full impairment analysis. If we determine that the carrying value of an asset group is not recoverable, a loss is recorded for the difference between the fair value and the carrying value. We evaluate our property, plant and equipment and intangibles on at least a segment level and at lower levels where cash flows for specific assets can be identified, which generally are groups of similar assets operated in the same geographic region, and the</p>	<p>Management considers the volume of commodities expected to be delivered to an asset and future commodity prices to estimate cash flows for each asset group. Management considers the expected net operating margin to be earned by customers for each customer contract intangible. Management uses discount rates commensurate with the risks involved for each asset considered. The amount of additional oil and gas developed by future drilling activity and expected net operating margin earned by customer depends, in part, on expected commodity prices. Projections of reserves, drilling activity, ability to renew contracts of significant customers, and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Management considers the</p>	<p>As of December 31, 2017, there were no indicators of impairment for any of our long-lived assets.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
customer relationship for our customer contract intangibles.	sustained reduction of commodity prices in forecasted cash flows.	
<i>Impairment of Goodwill</i>		
<p>Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of November 30 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. The first step of the evaluation is a qualitative analysis to determine if it is “more likely than not” that the carrying value of a reporting unit with goodwill exceeds its fair value. The additional quantitative steps in the goodwill impairment test may be performed if we determine that it is more likely than not that the carrying value is greater than the fair value.</p>	<p>Management performed a quantitative analysis as of November 30, 2017. We determined the fair value of our reporting units using the income and market approaches for our 2017 impairment analysis. This type of analysis requires us to make assumptions and estimates regarding industry and economic factors such as relevant commodity prices, contract renewals, and production volumes. 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.</p>	<p>The Partnership recorded no impairment charge related to our annual impairment review of goodwill as of November 30, 2017. The fair value of the reporting units for our goodwill impairment analysis was determined based on applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The discounted cash flow fair value estimate is based on known or knowable information at the measurement date. The significant assumptions that were used to develop the estimates of the fair values under the discounted cash flow method include management’s best estimates of the expected future results and discount rates, which range from 9 percent to 15 percent. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of the impairment tests will prove to be an accurate prediction of the future. As of December 31, 2017, the Partnership had six reporting units with goodwill: Marcellus (\$1.8 billion), East Texas (\$228 million), West Texas (\$41 million), HSM (\$11 million), MPL (\$130 million), and MPLXT (\$21 million). Step 1 of the fourth quarter impairment</p>
	<p>For the 2017 qualitative analysis, we analyzed the changes in the assumptions above in light of current economic conditions to determine if it was more likely than not that impairment exists. We looked at factors, including changes in the forecasted operating income and volumes for the six reporting units with goodwill, changes in the commodity price environment, changes in our per unit market value, changes in our peers’ market value and changes in industry EBITDA multiples.</p>	
	<p>Management is also required to make certain assumptions when identifying the reporting units and determining the amount of goodwill allocated to each reporting unit. The method of allocating goodwill resulting from the acquisitions involved</p>	

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
	<p>estimating the fair value of the reporting units and allocating the purchase price for each acquisition to each reporting unit. Goodwill is then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets.</p>	<p>analysis resulted in the fair value of the reporting units exceeding their carrying value by approximately 54 percent, 22 percent, 63 percent, 406 percent, 119 percent and 396 percent, respectively. An increase of 1.50 percent to the discount rate used to estimate the fair value of the reporting units would not have resulted in a goodwill impairment charge as of December 31, 2017. Our 2017 analysis resulted in a significant increase in the fair value of the reporting units as compared to the analysis performed during 2016. This increase was generally supported by an increase in our market capitalization of approximately 28 percent. Significant assumptions used to estimate the reporting units' fair value included estimates of future cash flows. If estimates for future cash flows, which are impacted primarily by producers' production plans and commodity prices, for the reporting units were to decline, the overall reporting units' fair value would decrease, resulting in potential goodwill impairment charges. Additionally, an increase in the cost of capital would result in a decrease in the fair value of the reporting units, causing their value to decline and goodwill to potentially be impaired.</p>

*Impairment of Equity Method Investments*

We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management's judgment, that the

Our impairment assessment requires us to apply judgment in estimating future cash flows received from or attributable to our equity method investments.

A fixed asset impairment analysis was performed during the second quarter of 2016 for Ohio Condensate Company (OCC) resulting in an

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p>carrying value of such investment may have experienced a decline in value. When evidence of an other-than-temporary loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment should be recorded.</p>	<p>The primary estimates may include the expected volumes, the terms of related customer agreements and future commodity prices.</p>	<p>impairment charge of \$96 million within OCC's financial statements. Approximately \$58 million of the charge was attributable to the Partnership based on its 60 percent ownership of OCC and was recorded in (Loss) income from equity method investments on the accompanying Consolidated Statements of Income. Furthermore, to determine the potential equity method impairment charge, an impairment analysis in accordance with ASC Topic 323 was performed during the second quarter of 2016 resulting in an additional impairment charge of approximately \$31 million, recorded in (Loss) income from equity method investments on the accompanying Consolidated Statements of Income.</p> <p>For purposes of the second quarter 2016 impairment analysis, the fair value of OCC was determined based on applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The significant assumptions used to estimate the fair value under the discounted cash flow method included management's best estimates of the expected results using a probability weighted average set of cash flow forecasts and using a discount rate of 11.2 percent. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As such, the fair value</p>



Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
		<p>of the OCC equity method investment and its underlying fixed assets represents a Level 3 measurement.</p> <p>No material events or circumstances indicated an other-than-temporary decline in our equity method investments during the year ended December 31, 2017.</p>
<p><i>Accounting for Risk Management Activities and Derivative Financial Instruments</i></p> <p>Our derivative financial instruments are recorded at fair value in the accompanying Consolidated Balance Sheets. Changes in fair value and settlements are reflected in our earnings in the accompanying Consolidated Statements of Income as gains and losses related to revenue, purchased product costs, and cost of revenues.</p>	<p>When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument's fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based on inputs that are largely unobservable such as option volatilities and NGL prices that are interpolated and extrapolated due to inactive markets. These instruments are classified as Level 3 under the fair value hierarchy. All fair value measurements are appropriately adjusted for non-performance risk.</p>	<p>If the assumptions used in the pricing models for our Level 2 and 3 financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different and we may be exposed to unrealized losses or gains that could be material. A 10 percent difference in our estimated fair value of Level 2 and 3 commodity derivatives (excluding embedded derivatives) at December 31, 2017 would have affected income before income taxes by less than \$1 million for the year ended December 31, 2017. Refer to <i>Accounting for Significant Embedded Derivative Instruments</i> for the sensitivity analysis over our embedded derivative.</p>
<p><i>Accounting for Significant Embedded Derivative Instruments</i></p> <p>Identifying embedded derivatives is complex and requires significant judgment. We have a gas purchase agreement with a producer customer in which we are required to purchase natural gas based on a complex</p>	<p>We carry the Natural Gas Embedded Derivative at fair value with changes in fair value recognized in income each period. The valuation requires significant judgment when forming the</p>	<p>The Natural Gas Embedded Derivative is an instrument that is not exchange-traded. The valuation of the instrument is complex and requires significant judgment. The inputs used in the</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p>formula designed to share some of the frac spread with the producer customer, through December 31, 2022. Additionally, we have a keep-whole gas processing agreement with the same producer customer. For accounting purposes, these two contracts have been aggregated into a single contract, and are evaluated together. The agreements have primary terms that expire on December 31, 2022 and contain two successive term-extending options under which the producer customer can extend the purchase and processing agreements an additional five years each. Neither contract may be extended without an election to extend the other contract.</p>	<p>assumptions used. Third-party forward curves for certain commodity prices utilized in the valuation do not extend through the term of the arrangement. Thus, pricing is required to be extrapolated for those periods. We utilize multiple cash flow techniques to extrapolate NGL pricing. Due to the illiquidity of future markets, we do not believe one method is more indicative of fair value than the other methods. The Natural Gas Embedded Derivative is classified as Level 3 under the fair value hierarchy. The fair value is also appropriately adjusted for non-performance risk each period.</p>	<p>valuation model require specialized knowledge, as NGL price curves do not exist for the entire term of the arrangement.</p>
<p>The feature of the gas purchase contract to purchase gas based on a complex formula designed to share some of the frac spread with the producer customer and the option to extend both contracts have been identified as a single embedded derivative (“Natural Gas Embedded Derivative”) that requires a complex valuation based on significant judgment. The option to extend the contracts is part of the embedded feature and thus is required to be considered in the valuation of the embedded derivative. We are required to make a significant judgment about the probability that the option would be exercised when determining the value of the embedded derivative.</p>	<p>We evaluated various factors in order to determine the probability that the term-extending options would be exercised by the producer customer, such as estimates of future gas reserves in the region, the competitive environment in which the producer customer operates, the commodity price environment and the producer customer’s business strategy. As of December 31, 2017, we have estimated the probability that the producer customer will exercise its option to extend the agreements for the first renewal period is 60 percent, and for the second renewal period is 80 percent based on the inherent uncertainty of the variables that would impact its decision.</p>	<p>The valuation is sensitive to NGL and natural gas future price curves. Holding the natural gas curves constant, a 10 percent increase (decrease) in NGL price curves causes a \$6 million increase (decrease) in the liability as of December 31, 2017. Holding the NGL curves constant, a 10 percent increase (decrease) in the natural gas curves causes a \$2 million (decrease) increase in the liability as of December 31, 2017. The determination of the fair value of the option to extend is based on our judgment about the probability of the producer customer exercising the extension. If it were determined that the probability of exercise was 25 percent for the first renewal period and 50 percent for the second renewal period as of December 31, 2017, the liability would be reduced by \$7 million. If it were determined that the probability of exercise was 75 percent for the first renewal period and 100 percent for the second renewal period as of December 31, the liability would be increased by \$10 million.</p>
<p><i>Variable Interest Entities</i></p>	<p>Significant judgment is exercised in determining that a legal entity is</p>	<p>See Item 8. Financial Statements and Supplementary Data—Note 16 for more information related to the Natural Gas Embedded Derivative.</p>
<p>We evaluate all legal entities in which we hold an ownership or other</p>	<p>MarkWest Utica EMG is our</p>	<p>most significant VIE; Ohio</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p>pecuniary interest to determine if the entity is a VIE.</p> <p>Our interests in a VIE are referred to as variable interests. Variable interests can be contractual, ownership or other pecuniary interests in an entity that change with changes in the fair value of the VIE's assets.</p> <p>When we conclude that we hold an interest in a VIE we must determine if we are the entity's primary beneficiary. A primary beneficiary is deemed to have a controlling financial interest in a VIE. This controlling financial interest is evidenced by both (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses that could potentially be significant to the VIE or the right to receive benefits that could potentially be significant to the VIE.</p> <p>We consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any interests in a VIE that is not consolidated (i.e. where we are not the primary beneficiary).</p>	<p>a VIE and in evaluating our interest in a VIE.</p> <p>We use primarily a qualitative analysis to determine if an entity is a VIE. We evaluate the entity's need for continuing financial support; the equity holder's lack of a controlling financial interest; and/or if an equity holder's voting interests are disproportionate to its obligation to absorb expected losses or receive residual returns.</p> <p>We evaluate our interests in a VIE to determine whether we are the primary beneficiary. We use a primarily qualitative analysis to determine if we are deemed to have a controlling financial interest in the VIE, either on a standalone basis or as part of a related party group.</p> <p>We continually monitor our interests in legal entities for changes in the design or activities of an entity and changes in our interests, including our status as the primary beneficiary to determine if the changes require us to revise our previous conclusions.</p>	<p>Condensate, Jefferson Dry Gas, and Sherwood Midstream are also VIEs. We are not considered to be the primary beneficiary for any of the entities. As a result, they are accounted for under the equity method. Changes in the design or nature of the activities of these VIEs, or our involvement with a VIE, may require us to reconsider our conclusions on the entity's status as a VIE and/or our status as the primary beneficiary. Such reconsideration requires significant judgment and understanding of the organization. This could result in the deconsolidation or consolidation of the affected subsidiary, which would have a significant impact on our financial statements.</p> <p>Ohio Gathering is a subsidiary of MarkWest Utica EMG and is a VIE. Sherwood Midstream Holdings is a subsidiary of Sherwood Midstream and is a VIE. If there were a change in consolidation conclusions for MarkWest Utica EMG or Sherwood Midstream, Ohio Gathering or Sherwood Midstream Holdings would need to be assessed for consolidation or deconsolidation, respectively.</p> <p>MarkWest Ohio Fractionation is a VIE and MPLX LP is considered the primary beneficiary. As a result, it is consolidated by MPLX LP.</p> <p>We account for our ownership interests in MarEn Bakken and Centrahoma under the equity method and have determined that these entities are not VIEs.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
		<p>However, changes in the design or nature of the activities of either entity may require us to reconsider our conclusions. Such reconsideration would require the identification of the variable interests in the entity and a determination on which party is the entity's primary beneficiary. If an equity investment were considered a VIE and we were determined to be the primary beneficiary, the change could cause us to consolidate the entity. The consolidation of an entity that is currently accounted for under the equity method could have a significant impact on our financial statements.</p> <p>See Item 8. Financial Statements and Supplementary Data—Note 5 for more information on our other investments.</p>
<p><i>Contingent Liabilities</i></p> <p>We accrue contingent liabilities for legal actions, claims, litigation, environmental remediation, tax deficiencies related to operating taxes and third-party indemnities for specified tax matters when such contingencies are both probable and can be reasonably estimated.</p>	<p>We regularly assess these estimates in consultation with legal counsel to consider resolved and new matters, material developments in court proceedings or settlement discussions, new information obtained as a result of ongoing discovery and past experience in defending and settling similar matters. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on degree of responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their</p>	<p>An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.</p> <p>For additional information on contingent liabilities, see Item 8. Financial Statements and Supplementary Data—Note 23.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
	interpretation, additional information on the extent and nature of site contamination and improvements in technology.	

### Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the FASB that we adopt as of the specified effective date. If not discussed in Item 8. Financial Statements and Supplementary Data—Note 3, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on our financial statements upon adoption.

### Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks related to the volatility of commodity prices. We employ various strategies, including the use of commodity derivative instruments, to economically hedge the risks related to these price fluctuations. We are also exposed to market risks related to changes in interest rates. As of December 31, 2017, we did not have any financial derivative instruments to economically hedge the risks related to interest rate fluctuations; however, we continually monitor the market and our exposure and may enter into these arrangements in the future. We are at risk for changes in fair value of all our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction.

#### Commodity Price Risk

We use a variety of commodity derivative instruments, including futures and options, as part of an overall program to economically hedge commodity price risk.

A portion of our profitability is directly affected by prevailing commodity prices primarily as a result of purchasing and selling NGLs and natural gas at index-related prices. To the extent that commodity prices influence the level of drilling by our producer customers, such prices also indirectly affect profitability. Derivative contracts utilized are primarily swaps traded on the OTC market and fixed price forward contracts. The risk management policy does not allow us to enter into speculative positions with our derivative contracts. Execution of our hedge strategy and the continuous monitoring of commodity markets and our open derivative positions are carried out by our hedge committee, comprised of members of senior management.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we primarily use NGL derivative swap contracts. A small portion of our NGL price exposure may be managed by using crude oil contracts.

To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily use natural gas derivative swap contracts, taking into account the partial offset of our long and short natural gas positions resulting from normal operating activities.

As a result of our current derivative positions, we have mitigated a portion of our expected commodity price risk through the fourth quarter of 2018. We would be exposed to additional commodity risk in certain situations such as if producers under-deliver or over-deliver products or if processing facilities are operated in different recovery modes. In the event that we have derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

Management conducts a standard credit review on counterparties to derivative contracts, and we have provided the counterparties with a guaranty as credit support for our obligations. A separate agreement with certain

counterparties allows MarkWest Liberty Midstream to enter into derivative positions without posting cash collateral. We use standardized agreements that allow for offset of certain positive and negative exposures in the event of default or other terminating events, including bankruptcy.

### Outstanding Derivative Contracts

The following tables provide information on the volume of our derivative activity for positions related to long liquids price risk at December 31, 2017, including the weighted-average prices (“WAVG”):

<u>Natural Gas Swaps</u>	<u>Volumes (MMBtu/d)</u>	<u>WAVG Price(Per MMBtu)</u>	<u>Fair Value (in thousands)</u>
2018	2,542	\$2.78	\$ (212)
<u>Propane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price(Per Gal)</u>	<u>Fair Value (in thousands)</u>
2018	16,925	\$0.64	\$(1,238)
<u>IsoButane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price(Per Gal)</u>	<u>Fair Value (in thousands)</u>
2018	1,655	\$0.80	\$ (102)
<u>Normal Butane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price(Per Gal)</u>	<u>Fair Value (in thousands)</u>
2018	4,595	\$0.75	\$ (297)
<u>Natural Gasoline Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price(Per Gal)</u>	<u>Fair Value (in thousands)</u>
2018	3,089	\$1.18	\$ (210)

We have a natural gas purchase commitment embedded in a keep-whole processing agreement with a producer customer in the Southern Appalachian region expiring in December 2022. The customer has the unilateral option to extend the agreement for two consecutive five year terms through December 2032. For accounting purposes, these natural gas purchase commitment and term extending options have been aggregated into a single compound embedded derivative. The probability of the customer exercising its options is determined based on assumptions about the customer’s potential business strategy decision points that may exist at the time they would elect whether to renew the contract. The changes in fair value of this compound embedded derivative are based on the difference between the contractual and index pricing, the probability of the producer customer exercising its option to extend and the estimated favorability of these contracts compared to current market conditions. The changes in fair value are recorded in earnings through *Purchased product costs* in the Consolidated Statements of Income. As of December 31, 2017 and 2016, the estimated fair value of this contract was a liability of \$64 million and \$54 million, respectively.

During the year ending December 31, 2017, we had a commodity contract that gave us an option to fix a component of the utilities cost to an index price on electricity at a plant location in the Southwest that expired as of December 31, 2017. Changes in the fair value as of the derivative component of this contract were recognized as *Cost of Revenues* in the Consolidated Statements of Income.

### Open Derivative Positions and Sensitivity Analysis

The following table sets forth information relating to our significant open commodity derivative contracts as of December 31, 2017.

	<u>Financial Position</u>	<u>Notional Quantity (net)</u>	<u>Weighted Average Price</u>
Natural Gas (MMBtu)	Long	928,003	\$2.78
NGLs (gal)	Short	9,586,503	\$0.73

The estimated fair value of our Level 2 and 3 financial instruments are sensitive to the assumptions used in our pricing models. Sensitivity analysis of a 10 percent difference in our estimated fair value of Level 2 and 3 commodity derivatives (excluding embedded derivatives) at December 31, 2017 would have affected income before income taxes by less than \$1 million for the year ended December 31, 2017. We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles.

### Interest Rate Risk

Sensitivity analysis of the effect of a hypothetical 100-basis-point change in interest rates on long-term debt, excluding capital leases, is provided in the following table. Fair value of cash and cash equivalents, receivables, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

<i>(In millions)</i>	<u>Fair Value as of December 31, 2017<sup>(1)</sup></u>	<u>Change in Fair Value <sup>(2)</sup></u>	<u>Change in Income before income taxes for the Year Ended December 31, 2017 <sup>(3)</sup></u>
Long-term debt			
Fixed-rate	\$7,213	\$569	N/A
Variable-rate	\$ 505	N/A	\$ 3

(1) Fair value was based on market prices, where available, or current borrowing rates for financings with similar terms and maturities.

(2) Assumes a 100-basis-point decrease in the weighted average yield-to-maturity at December 31, 2017.

(3) Assumes a 100-basis-point change in interest rates. The change to net income was based on the weighted average balance of all outstanding variable-rate debt for the year ended December 31, 2017.

At December 31, 2017, our portfolio of long-term debt consisted of fixed-rate instruments and variable-rate instruments under our revolving credit facility. The fair value of our fixed-rate debt is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value. Interest rate fluctuations generally do not impact the fair value of borrowings under our bank revolving credit or term loan facilities, but may affect our results of operations and cash flows. As of December 31, 2017, we did not have any financial derivative instruments to hedge the risks related to interest rate fluctuations; however, we continually monitor the market and our exposure and may enter into these agreements in the future.

### Credit Risk

We are subject to risk of loss resulting from non-payment by our customers to whom we provide services or sell natural gas or NGLs. We believe that certain contracts would allow us to pass those losses through to our customers, thus reducing our risk, when we are selling NGLs and acting as our producer customers' agent. Our credit exposure related to these customers is represented by the value of our trade receivables. Where exposed to credit risk, we analyze the customer's financial condition prior to entering into a transaction or agreement, establish credit terms and monitor the appropriateness of these terms on an ongoing basis. In the event of a customer default, we may sustain a loss and our cash receipts could be negatively impacted.

We are subject to risk of loss resulting from non-payment or non-performance by the counterparties to our derivative contracts. Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value at the reporting date. These outstanding instruments expose us to credit loss in the event of non-performance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate non-performance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.



## Item 8. Financial Statements and Supplementary Data

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### ***Management’s Responsibilities for Financial Statements***

The accompanying consolidated financial statements of MPLX LP and its subsidiaries (the “Partnership”) are the responsibility of management of the Partnership’s general partner, MPLX GP LLC, and have been prepared in conformity with accounting principles generally accepted in the United States of America. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

MPLX GP LLC seeks to assure the objectivity and integrity of the Partnership’s financial records by careful selection of its managers, by organizational arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The MPLX GP LLC Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit Committee. This committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

<u>/s/ Gary R. Heminger</u>	<u>/s/ Pamela K.M. Beall</u>	<u>/s/ C. Kristopher Hagedorn</u>
<i>Gary R. Heminger</i> <i>Chairman of the Board of Directors</i> <i>and Chief Executive Officer</i> <i>of MPLX GP LLC</i> <i>(the general partner of MPLX LP)</i>	<i>Pamela K.M. Beall</i> <i>Director, Executive Vice President</i> <i>and Chief Financial Officer</i> <i>of MPLX GP LLC</i> <i>(the general partner of MPLX LP)</i>	<i>C. Kristopher Hagedorn</i> <i>Vice President and Controller</i> <i>of MPLX GP LLC</i> <i>(the general partner of MPLX LP)</i>

### ***Management’s Report on Internal Control over Financial Reporting***

MPLX LP’s management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended). An evaluation of the design and effectiveness of our internal control over financial reporting, based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our chief executive officer and chief financial officer. Based on the results of this evaluation, MPLX LP’s management concluded that its internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of MPLX LP’s internal control over financial reporting as of December 31, 2017 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

<u>/s/ Gary R. Heminger</u>	<u>/s/ Pamela K.M. Beall</u>
<i>Gary R. Heminger</i> <i>Chairman of the Board of Directors</i> <i>and Chief Executive Officer</i> <i>of MPLX GP LLC</i> <i>(the general partner of MPLX LP)</i>	<i>Pamela K.M. Beall</i> <i>Director, Executive Vice President</i> <i>and Chief Financial Officer of</i> <i>MPLX GP LLC</i> <i>(the general partner of MPLX LP)</i>

## **Report of Independent Registered Public Accounting Firm**

To the Partners of MPLX LP and the Board of Directors of MPLX GP LLC

### ***Opinions on the Financial Statements and Internal Control over Financial Reporting***

We have audited the accompanying consolidated balance sheets of MPLX LP and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of income, of equity and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company’s internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the COSO.

### ***Basis for Opinions***

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

### ***Definition and Limitations of Internal Control over Financial Reporting***

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail,

accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Toledo, Ohio  
February 28, 2018

We have served as the Company's auditor since 2012.

**MPLX LP**  
**Consolidated Statements of Income**

*(In millions, except per unit data)*

	2017	2016	2015
<b>Revenues and other income:</b>			
Service revenue	\$ 1,156	\$ 958	\$ 130
Service revenue—related parties	1,082	936	701
Rental income	277	298	20
Rental income—related parties	279	235	146
Product sales	889	572	36
Product sales—related parties	8	11	1
Gain on sale of assets	—	1	—
Income (loss) from equity method investments	78	(74)	3
Other income	6	6	6
Other income—related parties	92	86	58
	<u>3,867</u>	<u>3,029</u>	<u>1,101</u>
<b>Costs and expenses:</b>			
Cost of revenues (excludes items below)	528	454	247
Purchased product costs	651	448	20
Rental cost of sales	62	57	11
Rental cost of sales—related parties	2	1	1
Purchases—related parties	455	388	172
Depreciation and amortization	683	591	129
Impairment expense	—	130	—
General and administrative expenses	241	227	125
Other taxes	54	50	15
	<u>2,676</u>	<u>2,346</u>	<u>720</u>
<b>Income from operations</b>	1,191	683	381
Related party interest and other financial costs	2	1	—
Interest expense (net of amounts capitalized of \$32 million, \$28 million, \$5 million, respectively)	296	210	35
Other financial costs	56	50	12
	<u>837</u>	<u>422</u>	<u>334</u>
<b>Income before income taxes</b>	837	422	334
Provision (benefit) for income taxes	1	(12)	1
	<u>836</u>	<u>434</u>	<u>333</u>
<b>Net income</b>	836	434	333
Less: Net income attributable to noncontrolling interests	6	2	1
Less: Net income attributable to Predecessor	36	199	176
	<u>794</u>	<u>233</u>	<u>156</u>
<b>Net income attributable to MPLX LP</b>	794	233	156
Less: Preferred unit distributions	65	41	—
Less: General partner's interest in net income attributable to MPLX LP	318	191	57
	<u>411</u>	<u>1</u>	<u>99</u>
<b>Limited partners' interest in net income attributable to MPLX LP</b>	\$ 411	\$ 1	\$ 99
<b>Per Unit Data (See Note 7)</b>			
<b>Net income attributable to MPLX LP per limited partner unit:</b>			
Common—basic	\$ 1.07	\$ —	\$ 1.23
Common—diluted	1.06	—	1.22
Subordinated—basic and diluted	—	—	0.11
<b>Weighted average limited partner units outstanding:</b>			
Common—basic	385	331	79
Common—diluted	388	338	80
Subordinated—basic and diluted	—	—	18
<b>Cash distributions declared per limited partner common unit</b>	\$2.2975	\$2.0500	\$1.8200

*The accompanying notes are an integral part of these consolidated financial statements.*

**MPLX LP**  
**Consolidated Balance Sheets**

<i>(In millions)</i>	December 31,	
	2017	2016
<b>Assets</b>		
Current assets:		
Cash and cash equivalents	\$ 5	\$ 234
Receivables, net	292	299
Receivables—related parties	160	247
Inventories	65	55
Other current assets	37	33
Total current assets	559	868
Equity method investments	4,010	2,471
Property, plant and equipment, net	12,187	11,408
Intangibles, net	453	492
Goodwill	2,245	2,245
Long-term receivables—related parties	20	11
Other noncurrent assets	26	14
Total assets	\$19,500	\$17,509
<b>Liabilities</b>		
Current liabilities:		
Accounts payable	\$ 151	\$ 140
Accrued liabilities	231	232
Payables—related parties	516	87
Deferred revenue	5	2
Deferred revenue—related parties	43	38
Accrued property, plant and equipment	194	146
Accrued taxes	38	38
Accrued interest payable	88	53
Other current liabilities	38	27
Total current liabilities	1,304	763
Long-term deferred revenue	42	12
Long-term deferred revenue—related parties	43	19
Long-term debt	6,945	4,422
Deferred income taxes	5	6
Deferred credits and other liabilities	188	177
Total liabilities	8,527	5,399
Commitments and contingencies (see Note 23)		
Redeemable preferred units	1,000	1,000
<b>Equity</b>		
Common unitholders—public (289 million and 271 million units issued and outstanding)	8,379	8,086
Class B unitholders (0 million and 4 million units issued and outstanding)	—	133
Common unitholder—MPC (95 million and 86 million units issued and outstanding)	1,278	1,069
Common unitholder—GP (23 million and 0 units issued and outstanding)	821	—
General partner—MPC (8 million and 7 million units issued and outstanding)	(637)	1,013
Accumulated other comprehensive loss	(14)	—
Equity of Predecessor	—	791
Total MPLX LP partners' capital	9,827	11,092
Noncontrolling interests	146	18
Total equity	9,973	11,110
Total liabilities, preferred units and equity	\$19,500	\$17,509

*The accompanying notes are an integral part of these consolidated financial statements.*

**MPLX LP**  
**Consolidated Statements of Cash Flows**

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>(Decrease) increase in cash and cash equivalents</b>			
<b>Operating activities:</b>			
Net income	\$ 836	\$ 434	\$ 333
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization of deferred financing costs	53	46	5
Depreciation and amortization	683	591	129
Impairment expense	—	130	—
Deferred income taxes	(1)	(17)	1
Asset retirement expenditures	(2)	(6)	(1)
Gain on disposal of assets	—	(1)	—
(Income) loss from equity method investments	(78)	74	(3)
Distributions from unconsolidated affiliates	241	148	15
Changes in:			
Current receivables	8	(52)	(29)
Inventories	(3)	(8)	1
Fair value of derivatives	6	43	(6)
Current accounts payable and accrued liabilities	48	102	5
Receivables from / liabilities to related parties	63	(19)	(34)
Prepaid other current assets from related parties	(8)	—	—
Deferred revenue	33	10	4
All other, net	28	16	7
Net cash provided by operating activities	<u>1,907</u>	<u>1,491</u>	<u>427</u>
<b>Investing activities:</b>			
Additions to property, plant and equipment	(1,411)	(1,313)	(334)
Acquisitions, net of cash acquired	(249)	—	(1,218)
Investments—net related party loans	80	(17)	(118)
Disposal of assets	7	1	—
Investments in unconsolidated affiliates	(761)	(87)	(14)
Distributions from unconsolidated affiliates—return of capital	26	—	—
All other, net	1	3	(2)
Net cash used in investing activities	<u>(2,307)</u>	<u>(1,413)</u>	<u>(1,686)</u>
<b>Financing activities:</b>			
Long-term debt—borrowings	2,911	434	1,490
—repayments	(416)	(1,312)	(1,441)
Related party debt—borrowings	2,369	2,532	301
—repayments	(1,983)	(2,540)	(293)
Debt issuance costs	(29)	—	(11)
Net proceeds from equity offerings	483	792	1
Issuance of redeemable preferred units	—	984	—
Issuance of units in MarkWest Merger	—	—	169
Contributions from MPC—MarkWest Merger	—	—	1,230
Distributions to preferred unitholders	(65)	(25)	—
Distributions of cash received from joint-interest acquisition entities to MPC	(20)	—	—
Distribution to MPC for acquisition	(1,931)	—	—
Distributions to unitholders and general partner	(1,120)	(845)	(158)
Distributions to noncontrolling interests	(7)	(3)	(1)
Contributions from noncontrolling interests	129	6	—
Consideration payment to Class B unitholders	(25)	(25)	—
Contribution from MPC	—	225	1
Distributions related to purchase of additional interest in Pipe Line Holdings	—	—	(12)
Distributions to MPC from Predecessor	(113)	(104)	—
All other, net	(12)	(6)	(1)
Net cash provided by financing activities	<u>171</u>	<u>113</u>	<u>1,275</u>
<b>Net (decrease) increase in cash and cash equivalents</b>	<u>(229)</u>	<u>191</u>	<u>16</u>
<b>Cash and cash equivalents at beginning of period</b>	<u>234</u>	<u>43</u>	<u>27</u>
<b>Cash and cash equivalents at end of period</b>	<u>\$ 5</u>	<u>\$ 234</u>	<u>\$ 43</u>

*The accompanying notes are an integral part of these consolidated financial statements.*

**MPLX LP**  
**Consolidated Statements of Equity**

<i>(In millions)</i>	Partnership						Accumulated	Non-controlling Interests	Equity of Predecessor	Total
	Common Unitholders Public	Class B Unitholders Public	Common Unitholder MPC	Subordinated Unitholder MPC	Common Unitholder GP	General Partner MPC	Other Comprehensive Loss			
<b>Balance at December 31, 2014</b>	\$ 639	\$ —	\$ 261	\$ 217	\$—	\$ (660)	\$—	\$ 6	\$ 321	\$ 784
Purchase of additional interest in Pipe Line Holdings	—	—	—	—	—	(6)	—	(6)	—	(12)
Contributions from MPC— MarkWest Merger	—	—	—	—	—	1,280	—	—	—	1,280
Issuance of units under ATM Program	1	—	—	—	—	—	—	—	—	1
Net income	15	—	36	48	—	57	—	1	176	333
Distributions to unitholders and general partner	(40)	—	(52)	(45)	—	(21)	—	—	—	(158)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(1)	—	(1)
Subordinated unit conversion	—	—	220	(220)	—	—	—	—	—	—
Contribution from MPC	—	—	—	—	—	—	—	—	1	1
Non-cash contribution from MPC	—	—	—	—	—	—	—	—	194	194
Equity-based compensation	17	—	—	—	—	—	—	—	—	17
Deferred income tax impact from changes in equity	(1)	—	—	—	—	—	—	—	—	(1)
Issuance of units in MarkWest Merger	7,060	266	—	—	—	169	—	—	—	7,495
Noncontrolling interests assumed in MarkWest Merger	—	—	—	—	—	—	—	13	—	13
<b>Balance at December 31, 2015</b>	<u>7,691</u>	<u>266</u>	<u>465</u>	<u>—</u>	<u>—</u>	<u>819</u>	<u>—</u>	<u>13</u>	<u>692</u>	<u>9,946</u>
Distributions to MPC from Predecessor	—	—	—	—	—	—	—	—	(104)	(104)
Contribution from MPC	—	—	84	—	—	141	—	—	—	225
Contribution of MarkWest Hydrocarbon from MPC	—	—	—	—	—	(188)	—	—	—	(188)
Distribution of MarkWest Hydrocarbon to MPC	—	—	—	—	—	563	—	—	—	563
Issuance of units under ATM Program	776	—	—	—	—	16	—	—	—	792
Net (loss) income	(5)	—	6	—	—	191	—	2	199	393
Allocation of MPC's net investment at acquisition	—	—	669	—	—	(337)	—	—	(332)	—
Distributions to unitholders and general partner	(513)	—	(142)	—	—	(190)	—	—	—	(845)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(3)	—	(3)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	6	—	6
Class B unit conversion	133	(133)	—	—	—	—	—	—	—	—
Non-cash contribution from MPC	—	—	—	—	—	—	—	—	336	336
Equity-based compensation	6	—	—	—	—	—	—	—	—	6
Deferred income tax impact from changes in equity	(2)	—	(13)	—	—	(2)	—	—	—	(17)
<b>Balance at December 31, 2016</b>	<u>8,086</u>	<u>133</u>	<u>1,069</u>	<u>—</u>	<u>—</u>	<u>1,013</u>	<u>—</u>	<u>18</u>	<u>791</u>	<u>11,110</u>
Distributions to MPC from Predecessor	—	—	—	—	—	—	—	—	(113)	(113)
Distributions of cash received from Joint-Interest Acquisition entities to MPC	—	—	—	—	—	(32)	—	—	—	(32)
Contribution from MPC	—	—	—	—	—	—	(14)	—	689	675
Issuance of units under ATM Program	473	—	—	—	—	10	—	—	—	483
Net income	301	—	98	—	12	318	—	6	36	771
Allocation of MPC's net investment at acquisition	—	—	845	—	824	(266)	—	—	(1,403)	—
Distribution to MPC for acquisitions	—	—	(537)	—	—	(1,394)	—	—	—	(1,931)
Distributions to unitholders and general partner	(622)	—	(197)	—	(15)	(286)	—	—	—	(1,120)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(7)	—	(7)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	129	—	129
Class B unit conversion	133	(133)	—	—	—	—	—	—	—	—
Equity-based compensation	8	—	—	—	—	—	—	—	—	8
<b>Balance at December 31, 2017</b>	<u>\$8,379</u>	<u>\$ —</u>	<u>\$1,278</u>	<u>\$ —</u>	<u>\$821</u>	<u>\$ (637)</u>	<u>\$ (14)</u>	<u>\$146</u>	<u>\$ —</u>	<u>\$ 9,973</u>

*The accompanying notes are an integral part of these consolidated financial statements.*



## *Notes to Consolidated Financial Statements*

### **1. Description of the Business and Basis of Presentation**

**Description of the Business**—MPLX LP is a diversified, growth-oriented master limited partnership formed by Marathon Petroleum Corporation. MPLX LP and its subsidiaries (collectively, the “Partnership”) are engaged in the gathering, processing and transportation of natural gas; the gathering, transportation, fractionation, storage and marketing of NGLs; and the transportation, storage and distribution of crude oil and refined petroleum products, principally for our sponsor. References to “MPC” refer collectively to Marathon Petroleum Corporation and its subsidiaries, other than the Partnership. The Partnership’s principal executive office is located in Findlay, Ohio.

The Partnership was formed on March 27, 2012 as a Delaware limited partnership and completed its Initial Offering on October 31, 2012. On December 4, 2015, the MarkWest Merger occurred, in which a wholly-owned subsidiary of the Partnership merged with MarkWest Energy Partners L.P. (“MarkWest”), one of the largest processors of natural gas in the United States and the largest processor and fractionator in the Marcellus and Utica shale plays. Effective March 31, 2016, the Partnership acquired MPC’s inland marine business, Hardin Street Marine LLC (“HSM”). Effective March 1, 2017, the Partnership acquired pipeline, storage and terminal businesses that are operated through Hardin Street Transportation LLC (“HST”), Woodhaven Cavern LLC (“WHC”) and MPLX Terminals LLC (“MPLXT”) from MPC. Effective September 1, 2017, the Partnership acquired certain ownership percentages in joint venture entities from MPC: all of the membership interests of Lincoln Pipeline LLC, which holds a 35 percent interest in Illinois Extension Pipeline Company, L.L.C. (“Illinois Extension”); all of the membership interests of MPL Louisiana Holdings LLC, which holds a 41 percent interest in LOOP LLC (“LOOP”); a 59 percent interest in LOCAP LLC (“LOCAP”); and a 25 percent interest in Explorer Pipeline Company (“Explorer”). These acquisitions, along with the MarkWest Merger, are described further in Note 4.

The Partnership’s business consists of two segments based on the nature of services it offers: Logistics and Storage (“L&S”), which is focused on crude oil and refined petroleum products, and Gathering and Processing (“G&P”), which is focused on natural gas and NGLs. See Note 10 for additional information regarding operations.

**Basis of Presentation**—The Partnership’s consolidated financial statements include all majority-owned and controlled subsidiaries. For non-wholly-owned consolidated subsidiaries, the interests owned by third parties have been recorded as *Noncontrolling interests* in the accompanying Consolidated Balance Sheets. Intercompany investments, accounts and transactions have been eliminated. The Partnership’s investments in which the Partnership exercises significant influence but does not control and does not have a controlling financial interest are accounted for using the equity method. The Partnership’s investments in a VIE in which the Partnership exercises significant influence but does not control and is not the primary beneficiary are also accounted for using the equity method. The accompanying consolidated financial statements of the Partnership have been prepared in accordance with GAAP.

### **2. Summary of Principal Accounting Policies**

**Use of Estimates**—The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ materially from those estimates. Estimates are subject to uncertainties due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change and affect items such as valuing identified intangible assets; determining the fair value of derivative instruments; valuing inventory; evaluating impairments of long-lived assets, goodwill and equity investments; establishing estimated useful lives

for long-lived assets; acquisition accounting; recognizing share-based compensation expense; estimating revenues, expense accruals and capital expenditures; valuing AROs; and determining liabilities, if any, for environmental and legal contingencies.

**Revenue Recognition**—The Partnership’s assessment of each of the revenue recognition criteria as they relate to its revenue producing activities are as follows: persuasive evidence of an arrangement exists, delivery, the fee is fixed or determinable and collectability is reasonably assured. It is upon delivery or title transfer to the customer that the Partnership meets all four revenue recognition criteria and it is at such time that the Partnership recognizes *Product sales*. Additionally, it is upon completion of services provided that the Partnership meets all four revenue recognition criteria and it is at such time that the Partnership recognizes *Service revenue*. The Partnership also recognizes *Rental income* over the term of implicit operating leases generating this revenue, as discussed below.

The Partnership generates revenue in the following ways:

- **Crude Oil and Refined Product Pipeline Transportation**—Revenues are recognized in the L&S segment for crude oil and product pipeline transportation based on the delivery of actual volumes transported at regulated tariff rates or at contractually agreed upon rates. These amounts are reported as *Service revenue* or *Service revenue—related parties* on the Consolidated Statements of Income.  
  
Under our MPC transportation service agreements, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay us a deficiency payment, as described in Note 6. The deficiency payments are initially recorded as *Deferred revenue—related parties* in the Consolidated Balance Sheets. The Partnership recognizes revenues for the deficiency payments at the earlier of when credits are used for volumes transported in excess of minimum volume commitments, when it becomes impossible to physically transport volumes necessary to utilize the credits or upon the expiration of the applicable four-quarter or eight-quarter period. In addition, capital projects the Partnership undertakes at the request of MPC are reimbursed in cash and recognized in income over the remaining term of the applicable transportation services agreements.
- **Crude Oil and Refined Product Storage**—Revenues are recognized in the L&S segment for crude oil and refined product storage as performed based on contractual rates. Revenue from storage services is reported as *Service revenue* or *Service revenue—related parties* on the Consolidated Statements of Income.
- **Crude Oil and Refined Product Marine Transportation**—Revenues are recognized in the L&S segment for marine transportation services for the transportation of cargo from a designated origin to a designated destination at a pre-established fixed rate. These amounts are reported as *Service revenue*, *Service revenue—related parties*, *Rental income*, or *Rental income—related parties* on the Consolidated Statements of Income.
- **Terminal Services Agreement**—Revenues are recognized in the L&S segment for the operation, storage, and other terminal related services, primarily performed for MPC, based on the receipt of actual throughput volumes at a fixed contractual fee. All such amounts are reported as *Service revenue—related parties* on the Consolidated Statements of Income. In addition, if MPC fails to meet its minimum volume commitment during any quarter, then MPC will pay the Partnership a deficiency payment equal to the volume of the deficiency multiplied by the contractual fee then in effect. The deficiency payments are recorded as *Deferred revenue—related parties* in the Consolidated Balance Sheets. Revenue for the deficiency payments is recognized at the end of each quarter that MPC does not meet its minimum volume commitment. Contingent revenue is recognized for volume throughput above MPC’s minimum volume commitment, and is reported as *Rental income—related parties* on the Consolidated Statements of Income.
- **Operating Services Agreements**—Revenues are recognized in the L&S segment for providing operation and maintenance services for various pipelines owned by MPC and third parties, based on negotiated fees. All such amounts are reported as *Service revenue* or *Service revenue—related parties* on the Consolidated Statements of Income.

- *Fee-based arrangements*—Revenues are recognized in the G&P segment for gathering, processing, transportation, fractionation, exchange and storage of natural gas, NGL's or crude oil based on the volume of natural gas, NGLs or crude oil that flows through the Partnership's systems and facilities. In certain cases, the arrangements provide for minimum annual payments or fixed demand charges. Revenue generated under these agreements is generally reported as *Service revenue* on the Consolidated Statements of Income. In certain instances, the Partnership purchases product after fee-based services have been provided. Revenue from the sale of such product is reported as *Product sales* or *Product sales—related parties* on the Consolidated Statements of Income and recognized on a gross basis as the Partnership is the principal in the transactions.
- *Percent-of-proceeds arrangements*—Under percent-of-proceeds arrangements in the G&P segment, the Partnership gathers and processes natural gas on behalf of producers, sells the resulting residue gas, condensate and NGLs at market prices and remits to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, the Partnership delivers an agreed-upon percentage of the residue gas and NGLs to the producer (take-in-kind arrangements) and sells the volumes the Partnership retains to third parties. Revenue from these arrangements is reported on a gross basis where the Partnership acts as the principal, as the Partnership has physical inventory risk and does not earn a fixed dollar amount. The agreed-upon percentage paid to the producer is reported as *Purchased product costs* on the Consolidated Statements of Income. Revenue is recognized on a net basis when the Partnership acts as an agent and earns a fixed dollar amount of physical product and does not have risk of loss of the gross amount of gas and/or NGLs. Percent-of-proceeds revenue is reported as *Product sales* on the Consolidated Statements of Income.
- *Keep-whole arrangements*—Under keep-whole arrangements in the G&P segment, the Partnership gathers natural gas from the producer, processes the natural gas and sells the resulting condensate and NGLs to third parties at market prices. Because the extraction of the condensate and NGLs from the natural gas during processing reduces the Btu content of the natural gas, the Partnership must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require the Partnership to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the NGL to gas ratio. Sales of NGLs under these arrangements are reported as *Product sales* on the Consolidated Statements of Income and are reported on a gross basis as the Partnership is the principal in the arrangement. Natural gas purchased to return to the producer and shared NGL profits are recorded as *Purchased product costs* in the Consolidated Statements of Income.
- *Purchase arrangements*—Under purchase arrangements in the G&P segment, the Partnership purchases natural gas and/or NGLs at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount. The Partnership may purchase product at the inlet or outlet of the facility. The Partnership then resells the natural gas or NGLs at the index price or at a different percentage discount to the index price. Revenue generated from purchase arrangements are reported as *Product sales* on the Consolidated Statements of Income and are recognized on a gross basis as the Partnership purchases and takes title to the product prior to sale and is the principal in the transaction.

In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described above. When fees are charged (in addition to product received) under keep-whole arrangements, percent-of-proceeds arrangements or percent-of-index arrangements, the Partnership records such fees as *Service revenue* on the Consolidated Statements of Income.

Amounts billed to customers for shipping and handling, including fuel costs, are included in *Product sales* on the Consolidated Statements of Income, except under contracts where we are acting as an agent. Shipping and handling costs associated with product sales are included in *Purchased product costs* on the Consolidated Statements of Income. Taxes collected from customers and remitted to the appropriate taxing authority are

excluded from revenue. Facility expenses and depreciation represent those expenses related to operating our various facilities and are necessary to provide both *Product sales* and *Service revenue*.

Based on the terms of certain agreements we are considered to be a lessor under several implicit operating lease arrangements in accordance with GAAP. In the L&S segment, these agreements primarily include fee-based transportation and storage services agreements with MPC, under which we are considered to be a lessor of our pipelines, marine equipment, terminals and storage facilities. Our implicit lease arrangements contain contingent rental provisions whereby we receive additional fees if the customer exceeds the monthly minimum throughput volumes. In the G&P segment, these agreements primarily relate to a natural gas gathering agreement in the Marcellus Shale for which it earns a fixed-fee for providing gathering services to a single producer using a dedicated gathering system. This agreement includes provisions to increase the fixed-fee as the gathering system is expanded. Other significant implicit leases relate to natural gas processing agreements in the Marcellus Shale and Southern Appalachia region for which the Partnership earns minimum monthly fees for providing processing services to a single producer using a dedicated processing plant. Revenue generated under implicit lease arrangements is reported as *Rental income* or *Rental income—related parties* on the Consolidated Statements of Income. Expenses generated in order to facilitate these agreements are reported as *Rental cost of sales* or *Rental cost of sales—related parties*.

**Revenue and Expense Accruals**—The Partnership routinely makes accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third-party information and reconciling the Partnership’s records with those of third parties. The delayed information from third parties includes, among other things, actual volumes purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL deliveries and other operating expenses. The Partnership makes accruals to reflect estimates for these items based on its internal records and information from third parties. Estimated accruals are adjusted when actual information is received from third parties and the Partnership’s internal records have been reconciled.

**Cash and Cash Equivalents**—Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with initial maturities of three months or less.

**Restricted Cash**—Restricted cash consists of cash and investments that must be maintained as collateral for letters of credit issued to certain third-party producer customers. The balances will be outstanding until certain capital projects are completed and the third party releases the restriction. Restricted cash also consists of cash advances to be used for the operation and maintenance of an operated pipeline. At December 31, 2017 and 2016, the amount of restricted cash included in *Other current assets* on the Consolidated Balance Sheets was \$4 million and \$5 million, respectively.

**Receivables**—Receivables primarily consist of customer accounts receivable, which are recorded at the invoiced amount and generally do not bear interest. Management reviews the allowance quarterly. Past-due balances over 90 days and other higher- risk amounts are reviewed individually for collectability. Balances that remain outstanding after reasonable collection efforts have been unsuccessful are written off through a charge to the valuation allowance and a credit to accounts receivable.

**Inventories**—Inventories consist primarily of natural gas, propane, other NGLs and materials and supplies to be used in operations. Natural gas, propane, and other NGLs are valued at the lower of weighted-average cost or net realizable value. Materials and supplies are stated at the lower of cost or net realizable value. Cost for materials and supplies are determined primarily using the weighted-average cost method. Processed natural gas and NGL inventories include material, labor and overhead. Shipping and handling costs related to purchases of natural gas and NGLs are included in inventory.

**Imbalances**—Within our pipelines and storage assets, we experience volume gains and losses due to pressure and temperature changes, evaporation and variances in meter readings and other measurement methods. Until

settled, positive imbalances are recorded as other current assets and negative imbalances are recorded as accounts payable. Positive and negative product imbalances are settled in cash, settled by physical delivery of gas from a different source, or tracked and settled in the future.

**Property, Plant and Equipment**—Property, plant and equipment are recorded at cost. Expenditures that extend the useful lives of assets are capitalized. Repairs, maintenance and renewals that do not extend the useful lives of the assets are expensed as incurred. Interest costs for the construction or development of long-lived assets are capitalized and amortized over the related asset's estimated useful life. Leasehold improvements are amortized over the shorter of the useful life or lease term.

When items of property, plant and equipment are sold or otherwise disposed of, any gains or losses are reported in the Consolidated Statements of Income. Gains on the disposal of property, plant and equipment are recognized when they occur, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. The Partnership evaluates transactions involving the sale of property, plant and equipment to determine if they are in-substance, the sale of real estate. Tangible assets may be considered real estate if the costs to relocate them for use in a different location exceed 10 percent of the asset's fair value. Financial assets, primarily in the form of ownership interests in an entity, may be in-substance real estate based on the significance of the real estate in the entity. Sales of real estate are not considered consummated if the Partnership maintains an interest in the asset after it is sold or has certain other forms of continuing involvement. Significant judgment is required to determine if a transaction is a sale of real estate and if a transaction has been consummated. If a sale of real estate is not considered consummated, the Partnership cannot record the transaction as a sale and must account for the transaction under an alternative method of accounting such as a financing or leasing arrangement.

The Partnership's policy is to evaluate whether there has been an impairment in the value of long-lived assets when certain events indicate that the remaining balance may not be recoverable. Qualitative and quantitative information is reviewed in order to determine if a triggering event has occurred or if an impairment indicator exists. If we determine that a triggering event has occurred we would complete a full impairment analysis. If we determine that the carrying value of a reporting unit is not recoverable, a loss is recorded for the difference between the fair value and the carrying value. The Partnership evaluates the carrying value of its property, plant and equipment on at least a segment level and at lower levels where the cash flows for specific assets can be identified, which generally is the component level for our G&P and L&S segments. Management considers the dedicated volume of producer customers' reserves and future NGL product and natural gas prices to estimate cash flows. The amount of additional producer customers' reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of producer customers' reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Any significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset group.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value, less the cost to sell, to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is redetermined when related events or circumstances change.

**Intangibles**—The Partnership's intangibles are mainly comprised of customer contracts and related relationships acquired in business combinations and recorded under the acquisition method of accounting at their estimated fair values at the date of acquisition. Using relevant information and assumptions, management determines the fair value of acquired identifiable intangible assets. Fair value was calculated using the multi-period excess earnings method under the income approach for each reporting unit. This valuation method is based on first forecasting gross profit for the existing customer base and then applying expected attrition rates. The operating cash flows are calculated by determining the costs required to generate gross profit from the existing customer base. The key assumptions include overall gross profit growth, attrition rate of existing customers over time and the discount rate. Amortization of intangibles with definite lives is calculated using the straight-line method

which is reflective of benefit pattern in which the estimated economic benefit is expected to be received over the estimated useful life of the intangible asset. The estimated economic life is determined by assessing the life of the assets related to the contracts and relationships, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions and maintenance and renewal costs.

Intangibles with indefinite lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the intangible may not be recoverable. If the sum of the expected undiscounted future cash flows related to the asset is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. The Partnership has no intangibles with indefinite lives.

**Goodwill**—Goodwill is the cost of an acquisition less the fair value of the net identifiable assets and noncontrolling interests, if any, of the acquired business. The Partnership evaluates goodwill for impairment annually as of November 30, 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. The Partnership determined its reporting units based on the criteria included in ASC 280 which requires a component to be a business with discrete financial information that management reviews on a regular basis. Management reviews its determination of reporting units on an annual basis. The Partnership may first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. During 2016, impairment charges of approximately \$130 million were recorded. There were no impairments as a result of the Partnership's November 30, 2017 and November 30, 2016 annual goodwill impairment analyses.

**Other Taxes**—Other taxes primarily include real estate taxes.

**Environmental Costs**—Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. The Partnership recognizes remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure.

**Asset Retirement Obligations**—An ARO is a legal obligation associated with the retirement of tangible long-lived assets that generally result from the acquisition, construction, development or normal operation of the asset. AROs 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 increases due to the passage of time based on the time value of money until the obligation is settled. The Partnership recognizes a liability of a conditional ARO as soon as the fair value of the liability can be reasonably estimated. A conditional ARO is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. AROs have not been recognized for certain assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate. Such obligations will be recognized in the period when sufficient information becomes available to estimate a range of potential settlement dates.

**Investment in Unconsolidated Affiliates**—Equity investments in which the Partnership exercises significant influence, but does not control and is not the primary beneficiary, are accounted for using the equity method and are reported in *Equity method investments* in the accompanying Consolidated Balance Sheets. This includes entities in which we hold majority ownership but the minority shareholders have substantive participating rights. Differences in the basis of the investments and the separate net asset values of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets and liabilities, except for the excess related to goodwill.

The Partnership believes the equity method is an appropriate means for it to recognize increases or decreases measured by GAAP in the economic resources underlying the investments. Regular evaluation of these investments is appropriate to evaluate any potential need for impairment. The Partnership uses evidence of a loss in value to identify if an investment has an other than a temporary decline.

**Deferred Financing Costs**—Deferred financing costs are an asset for credit facility costs and netted against debt for senior notes. These costs are amortized over the contractual term of the related obligations using the effective interest method or, in certain circumstances, accelerated if the obligation is refinanced.

**Derivative Instruments**—The Partnership uses commodity derivatives to economically hedge a portion of its exposure to commodity price risk. All derivative instruments (including derivatives embedded in other contracts) are recorded at fair value. Certain commodity derivatives are reflected on the consolidated balance sheets on a net basis by counterparty as they are governed by master netting arrangements. The Partnership discloses the fair value of all derivative instruments under the captions *Other noncurrent assets*, *Other current liabilities* and *Deferred credits and other liabilities* on the Consolidated Balance Sheets. Changes in the fair value of derivative instruments are reported in the Consolidated Statements of Income in accounts related to the item whose value or cash flows are being managed. All derivative instruments were marked to market through *Product sales*, *Purchased product costs*, or *Cost of revenues* on the Consolidated Statements of Income. Revenue gains and losses relate to contracts utilized to manage the cash flow for the sale of a product, typically NGLs. Purchased product costs gains and losses relate to contracts utilized to manage the cost of natural gas purchases, typically related to keep-whole arrangements. Cost of revenues gains and losses relate to a contract utilized to manage electricity costs. Changes in risk management for unrealized activities are reported as an adjustment to net income in computing cash flow from operating activities on the accompanying Consolidated Statements of Cash Flows.

During the years ended December 31, 2017, 2016 and 2015, the Partnership did not elect hedge accounting for any derivatives. The Partnership has elected the normal purchases and normal sales designation for certain contracts related to the physical purchase of electric power.

**Fair Value of Financial Instruments**—Management believes the carrying amount of financial instruments, including cash and cash equivalents, receivables, receivables from related parties, other current assets, accounts payable, accounts payable to related parties and accrued liabilities approximate fair value because of the short-term maturity of these instruments. The recorded value of the amounts outstanding under the bank revolving credit facility, if any, approximate fair value due to the variable interest rate that approximates current market rates (see Note 15). Derivative instruments are recorded at fair value, based on available market information (see Note 16).

**Fair Value Measurement**—Financial assets and liabilities recorded at fair value in the Consolidated Balance Sheets are categorized based upon the fair value hierarchy established by GAAP, which classifies the inputs used to measure fair value into Level 1, Level 2 or Level 3. A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The methods and assumptions utilized may produce a fair value that may not be realized in future periods upon settlement. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, 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. For further discussion see Note 15.

**Equity-Based Compensation Arrangements**—The Partnership issues phantom units under its share-based compensation plan as described further in Note 20. A phantom unit entitles the grantee a right to receive a common unit upon the issuance of the phantom unit. The fair value of phantom unit awards granted to employees and non-employee directors is based on the fair market value of MPLX LP common units on the date of grant. The fair value of the units awarded is amortized into earnings using a straight-line amortization schedule over the period of service corresponding with the vesting period. For phantom units that vest immediately and are not forfeitable, equity-based compensation expense is recognized at the time of grant.

Performance units paying out in cash are accounted for as liability awards and recorded at fair value with a mark-to-market adjustment made each quarter. The performance units paying out in units are accounted for as equity awards and use a Monte Carlo valuation model to calculate a grant date fair value.

To satisfy common unit awards, the Partnership may issue new common units, acquire common units in the open market or use common units already owned by the general partner.

**Tax Effects of Share-Based Compensation**—The Partnership elected to adopt the simplified method to establish the beginning balance of the additional paid-in capital pool (“APIC Pool”) related to the tax effects of employee share-based compensation and to determine the subsequent impact on the APIC Pool and Consolidated Statements of Cash Flows of the tax effects of share-based compensation awards that were outstanding upon adoption. Additional paid-in capital is reported as *Common unitholders—public* in the accompanying Consolidated Balance Sheets.

**Income Taxes**—The Partnership is not a taxable entity for federal income tax purposes. As a result of the MarkWest Merger, discussed further in Note 4, MarkWest was the surviving entity for tax purposes. MarkWest is not a taxable entity for federal income tax purposes. As such, the Partnership does not directly pay federal income tax. Taxes on the Partnership’s net income generally are borne by its partners through the allocation of taxable income. The Partnership’s taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The Partnership and certain legal entities are, however, taxable entities under certain state jurisdictions.

As a result of the Class A Reorganization discussed in Note 8, MarkWest Hydrocarbon, L.L.C. (“MarkWest Hydrocarbon” and MarkWest Hydrocarbon, Inc. prior to the Class A Reorganization) is no longer a tax paying entity for federal income tax purposes or for the majority of states that impose an income tax effective September 1, 2016. Prior to the Class A Reorganization, in addition to paying tax on its own earnings, MarkWest Hydrocarbon recognized a tax expense or a tax benefit on its proportionate share of Partnership income or loss resulting from MarkWest Hydrocarbon’s ownership of Class A units of the Partnership, even though for financial reporting purposes such income or loss was eliminated in consolidation. The Class A units represented limited partner interests with the same rights as common units except that the Class A units did not have voting rights, except as required by law. Class A units were not treated as outstanding common units in the Consolidated Balance Sheets as they were eliminated in the consolidation of MarkWest Hydrocarbon. The deferred income tax component prior to the reorganization related to the change in the temporary book to tax basis difference in the carrying amount of the investment in the Partnership which resulted primarily from timing differences in MarkWest Hydrocarbon’s proportionate share of the book income or loss as compared with the MarkWest Hydrocarbon’s proportionate share of the taxable income or loss of the Partnership.

The Partnership accounts for income taxes under the asset and liability method. Deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis, capital loss carryforwards and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates



applied to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized as tax expense (benefit) from continuing operations in the period that includes the enactment date of the tax rate change. Realizability of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to reflect the deferred tax assets at net realizable value as determined by management. All deferred tax balances are classified as long-term in the accompanying Consolidated Balance Sheets. All changes in the tax bases of assets and liabilities are allocated among operations and items charged or credited directly to equity.

**Distributions**—In preparing the Consolidated Statements of Equity, net income attributable to MPLX LP is allocated to Preferred unitholders based on a fixed distribution schedule, as discussed in Note 9, and subsequently allocated to the general partner and limited partner unitholders. Distributions, although earned, are not accrued as a liability until declared. However, when distributions related to the IDRs are made, earnings equal to the amount of those distributions are first allocated to the general partner before the remaining earnings are allocated to the limited partner unitholders based on their respective ownership percentages. The allocation of net income attributable to MPLX LP for purposes of calculating net income per limited partner unit is described in below.

**Net Income Per Limited Partner Unit**—The Partnership uses the two-class method when calculating the net income per unit applicable to limited partners, because there is more than one class of participating security. The classes of participating securities include common units, subordinated units, general partner units, preferred units, certain equity-based compensation awards and IDRs. Class B units are considered to be a separate class of common units that do not participate in distributions.

Net income attributable to MPLX LP is allocated to the unitholders differently for preparation of the Consolidated Statements of Equity and the calculation of net income per limited partner unit. In preparing the Consolidated Statements of Equity, net income attributable to MPLX LP is allocated to Preferred unitholders based on a fixed distribution schedule and subsequently allocated to remaining unitholders in accordance with their respective ownership percentages. However, when distributions related to the IDRs are made, earnings equal to the amount of those distributions are first allocated to the general partner before the remaining earnings are allocated to the unitholders, except Class B unitholders, based on their respective ownership percentages.

In preparing net income per limited partner units, during periods in which a net loss attributable to the Partnership is reported or periods in which the total distributions exceed the reported net income attributable to the Partnership's unitholders, the amount allocable to certain equity-based compensation awards is based on actual distributions to the equity-based compensation awards. Diluted earnings per unit is calculated by dividing net income attributable to the Partnership's common unitholders, after deducting amounts allocable to other participating securities, by the weighted average number of common units and potential common units outstanding during the period. Potential common units are excluded from the calculation of diluted earnings per unit during periods in which net income attributable to the Partnership's unitholders, after deducting amounts that are allocable to the outstanding equity-based compensation awards, Preferred units, and IDRs, is a loss as the impact would be anti-dilutive.

**Business Combinations**—The Partnership recognizes and measures the assets acquired and liabilities assumed in a business combination based on their estimated fair values at the acquisition date, with any remaining difference recorded as goodwill or gain from a bargain purchase. For all material acquisitions, management engages an independent valuation specialist to assist with the determination of fair value of the assets acquired, liabilities assumed, noncontrolling interests, if any, and goodwill, based on recognized business valuation methodologies. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition, and not later than one year from the acquisition date, the Partnership will record any material adjustments to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date. An income, market or cost valuation method may be utilized to estimate the fair value of the assets

acquired, liabilities assumed, and noncontrolling interests, if any, in a business combination. The income valuation method represents the present value of future cash flows over the life of the asset using: (i) discrete financial forecasts, which rely on management's estimates of volumes, NGL prices, revenue and operating expenses; (ii) long-term growth rates; and (iii) appropriate discount rates. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset. Acquisition-related costs are expensed as incurred in connection with each business combination. See Note 4 for more information about the acquisitions.

***Accounting for Changes in Ownership Interests in Subsidiaries***—The Partnership's ownership interest in a consolidated subsidiary may change if it sells a portion of its interest or acquires additional interest or if the subsidiary issues or repurchases its own shares. If the transaction does not result in a change in control over the subsidiary, the transaction is accounted for as an equity transaction. If a sale results in a loss of control, it would result in the deconsolidation of a subsidiary with a gain or loss recognized in the Consolidated Statements of Income unless the subsidiary meets the definition of in-substance real estate. Deconsolidation of in-substance real estate is recorded at cost with no gain or loss recognized. If the purchase of additional interest occurs which changes the acquirer's ownership interest from noncontrolling to controlling, the acquirer's preexisting interest in the acquiree is remeasured to its fair value, with a resulting gain or loss recorded in earnings upon consummation of the business combination. Once an entity has control of a subsidiary, its acquisitions of some or all of the noncontrolling interests in that subsidiary are accounted for as equity transactions and are not considered to be a business combination.

### **3. Accounting Standards**

#### ***Recently Adopted***

In October 2016, the FASB issued an accounting standards update to amend the consolidation guidance issued in February 2015 to require that a decision maker consider, in the determination of the primary beneficiary, its indirect interest in a VIE held by a related party that is under common control on a proportionate basis only. The change was effective for the financial statements for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. The Partnership was required to apply the standard retrospectively to January 1, 2016, the date on which the Partnership adopted the consolidation guidance issued in February 2015. The Partnership adopted this accounting standards update in the first quarter of 2017 and it did not have an impact on the consolidated financial statements.

In March 2016, the FASB issued an accounting standards update on the accounting for employee share-based payments. This update requires the recognition of income tax effects of awards through the income statement when awards vest or are settled. It also increases the amount an employer can withhold for tax purposes without triggering liability accounting. Lastly, it allows employers to make a policy election to account for forfeitures as they occur. The changes were effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Under the new guidance, the Partnership will continue estimating forfeiture rates to calculate compensation cost. The Partnership adopted this accounting standards update in the first quarter of 2017 and it did not have a material impact on the consolidated financial statements.

#### ***Not Yet Adopted***

In August 2017, the FASB issued an accounting standards update to amend the hedge accounting rules to simplify the application of hedge accounting guidance and better portray the economic results of risk management activities in the financial statements. The guidance expands the ability to hedge nonfinancial and financial risk components, reduces complexity in fair value hedges of interest rate risk, eliminates the requirement to separately measure and report hedge ineffectiveness, as well as eases certain hedge effectiveness assessment requirements. The guidance is effective beginning in 2019 with early adoption permitted. The

Partnership is in the process of determining the impact of this guidance, including transition elections and required disclosures, on the consolidated financial statements and the timing of adoption.

In May 2017, the FASB issued an accounting standards update to provide guidance about when changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. An entity should account for the effects of a modification unless the fair value, vesting conditions and balance sheet classification of the modified award is the same as the original award immediately before the original award is modified. The Partnership will adopt the new standard on a prospective basis beginning on January 1, 2018. The application of this new accounting standard will not have a material impact on the consolidated financial statements.

In February 2017, the FASB issued an accounting standards update addressing the derecognition of nonfinancial assets. The guidance defines in-substance nonfinancial assets, and states that the derecognition of business activities should be evaluated under the consolidation guidance, with limited exceptions related to conveyances of oil and gas mineral rights or contracts with customers. The standard eliminates the previous exclusion for businesses that are in-substance real estate, and eliminates some differences based on whether a transferred set is that of assets or a business and whether the transfer is to a joint venture. The standard must be adopted in conjunction with the adoption date of the revenue recognition accounting standards update, which the Partnership will adopt on January 1, 2018. The Partnership plans to adopt the new standard using the modified retrospective method and does not expect the application of this accounting standards update to have a material impact on the consolidated financial statements.

In January 2017, the FASB issued an accounting standards update which simplifies the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test. Under the new guidance, the recognition of an impairment charge is calculated based on the amount by which the carrying amount exceeds the reporting unit's fair value, which could be different from the amount calculated under the current method using the implied fair value of the goodwill; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. The guidance should be applied on a prospective basis, and is effective for annual or interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017.

In January 2017, the FASB issued an accounting standards update to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is intended to narrow the definition of a business by specifying the minimum inputs and processes and by narrowing the definition of outputs. The change is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The guidance will be applied prospectively and early adoption is permitted for certain transactions. The Partnership will adopt this new standard on a prospective basis beginning on January 1, 2018. The application of this accounting standards update will not have a material impact on the consolidated financial statements.

In November 2016, the FASB issued an accounting standards update requiring that the statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The change is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Retrospective application is required. Application of this accounting standards update is not expected to have a material impact on the Consolidated Statements of Cash Flows.

In August 2016, the FASB issued an accounting standards update related to the classification of certain cash flows. The accounting standards update provides specific guidance on eight cash flow classification issues, including debt prepayment or debt extinguishment costs and distributions received from equity method investees, to reduce diversity in practice. The change is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. Retrospective application is required.

The Partnership will adopt this new standard beginning on January 1, 2018. The application of this accounting standards update adds additional disclosures related to the Partnership's Consolidated Statements of Cash Flows but otherwise has no impact on the consolidated financial statements.

In June 2016, the FASB issued an accounting standards update related to the accounting for credit losses on certain financial instruments. The guidance requires that for most financial assets, losses are based on an expected loss approach which includes estimates of losses over the life of exposure that considers historical, current and forecasted information. Expanded disclosures related to the methods used to estimate the losses as well as a specific disaggregation of balances for financial assets are also required. The change is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Partnership does not expect application of this accounting standards update to have a material impact on the consolidated financial statements.

In February 2016, the FASB issued an accounting standards update requiring lessees to record virtually all leases on their balance sheets. The accounting standards update also requires expanded disclosures to help financial statement users better understand the amount, timing and uncertainty of cash flows arising from leases. For lessors, this amended guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. The change will be effective on a modified retrospective basis for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. The Partnership is currently evaluating the impact of this standard on the Partnership's financial statements and disclosures, internal controls, and accounting policies. This evaluation process includes reviewing all forms of leases, performing a completeness assessment over the lease population and analyzing the practical expedients in order to determine the best path to implementation. The Partnership completed its system implementation evaluation during the fourth quarter of 2017, and concluded a third-party supported lease accounting information system solution will be implemented to account for its leases. A project to implement this system has begun and the Partnership is currently collecting the necessary information on its lease population, establishing a new lease accounting process and designing new internal controls for the new process. The Partnership does not plan to early adopt the standard. The Partnership believes the impact may be material on the consolidated financial statements as all operating leases will be recognized as a right of use asset and lease obligation. Based on results of the evaluation process to date, the Partnership also believes the impact on existing processes, controls and information systems may be material.

In January 2016, the FASB issued an accounting standards update requiring unconsolidated equity investments, not accounted for under the equity method, to be measured at fair value with changes in fair value recognized in net income. The update also requires the use of the exit price notion when measuring the fair value of financial instruments for disclosure purposes and the separate presentation of financial assets and liabilities by measurement category and form on the balance sheet and accompanying notes. The update eliminates the requirement to disclose the methods and assumptions used in estimating the fair value of financial instruments measured at amortized cost. Lastly, the accounting standards update requires separate presentation in other comprehensive income of the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when electing to measure the liability at fair value in accordance with the fair value option for financial instruments. The changes are effective for fiscal years and interim periods within those fiscal years beginning after December 15, 2017. Early adoption is permitted only for guidance regarding presentation of the liability's credit risk. The Partnership does not expect application of this accounting standards update to have a material impact on the consolidated financial statements.

In May 2014, the FASB issued an accounting standards update for revenue recognition for contracts with customers. The guidance in the accounting standards update states that revenue is recognized when a customer obtains control of a good or service. Recognition of the revenue will involve a multiple step approach including identifying the contract, identifying the separate performance obligations, determining the transaction price, allocating the price to the performance obligations and recognizing the revenue as the obligations are satisfied.

Additional disclosures will be required to provide adequate information to understand the nature, amount, timing and uncertainty of reported revenues and revenues expected to be recognized. The Partnership completed the evaluation of the impact of this standard on the consolidated financial statements and disclosures, internal controls and accounting policies in the fourth quarter of 2017. The Partnership will adopt the standard January 1, 2018, using the modified retrospective method applied to contracts not complete as of the adoption date, resulting in an immaterial cumulative effect adjustment as of the date of adoption. The Partnership will monitor the changes in processes and internal controls throughout 2018. There will be no significant system or process changes as a result of adoption. The major changes as a result of adoption are analyzed below. Our equity method investments in private companies that we do not manage are still in the process of analyzing the impact of ASC 606 which will be adopted as of January 1, 2019. Based on the nature of these companies operations and similarities to our operations for which we have analyzed the impact of ASC 606, we do not expect the impact to be material.

Under ASC 606, the Partnership's service arrangements will generally be recognized over time when the performance obligation is satisfied as services are provided in a series. The transaction price has both fixed components, related to minimum volume commitments, and variable components which are primarily dependent on volumes delivered. Variable consideration will not be estimated at contract inception as the transaction price is specifically allocable to the services provided each period end. *Product sales* will be recognized at a point in time when control of the product transfers to the customer. The primary changes on the Consolidated Statements of Income as a result of the adoption of ASC 606 are as follows:

- *Third party reimbursements*—Amounts received from customers for reimbursement of costs such as electricity and storage historically were recorded net in the statement of operations. Upon adoption, these amounts will be included in the transaction price for services performed and thus will be a gross up on the statement of operations. Had the Partnership adopted ASC 606 for fiscal year-ended December 31, 2017, the Partnership believes the impact would have been an increase of between \$365 million to \$403 million on *Service revenue* and *Cost of revenues*.
- *Non-cash consideration*—The Partnership receives commodity product for services performed in percent-of-liquids and keep-whole arrangements. A new service revenue stream for non-cash consideration received in these arrangements will be recorded when the performance obligation is completed based on the value of the product received at the time services are performed. At this time, the variability of the non-cash consideration related to both form (price) and other-than-form (volume and product mix), which are interrelated, is resolved. Fuel and loss allowances will not be included in the transaction price from contracts with customers as the Partnership does not obtain control of the product prior to being used or burned, which is consistent with historical accounting. Had the Partnership adopted ASC 606 for fiscal year-ended December 31, 2017, the Partnership believes the impact would have been an increase of between \$52 million to \$58 million on *Service revenue* and *Cost of revenues*.
- *Percent-of-proceeds revenues*—The Partnership's percentage of proceeds revenue received was historically recorded in product revenues. Upon adoption of ASC 606, these revenues will be classified in *Service revenue*, as the performance obligation related to these contracts is to provide gathering and processing services. Revenues will continue to be recorded net under these arrangements as the Partnership does not control the product prior to sale. Had the Partnership adopted ASC 606 for fiscal year-ended December 31, 2017, the Partnership believes the impact would have been an increase on *Service revenue* and a decrease on *Product sales* of between \$119 million to \$131 million.
- *Imbalances*—Historically, all imbalances were recorded net. In certain instances, the Partnership's arrangements are structured such that imbalances are cashed-out each period end which results in the transfer of control of a commodity and creates a purchase and/or sale of a commodity under ASC 606. Thus, certain imbalances will be grossed up as a result of adoption. Had the Partnership adopted ASC 606 for fiscal year-ended December 31, 2017, the Partnership believes the impact would have been an increase of between \$63 million to \$69 million on *Product sales* and *Purchased product costs*.

There were various other adoption differences between ASC 605 and ASC 606 identified as a result of adopting ASC 606; however, these changes did not have a material impact on the Partnership's consolidated financial statements. These changes in process or recognition patterns relate specifically to oil allowances, deferred customer credits, arrangements with tiered pricing features or discounts and aid-in-construction payments.

#### 4. Acquisitions

##### *Joint-Interest Acquisition*

On September 1, 2017, the Partnership entered into a Membership Interests and Shares Contributions Agreement (the "September 2017 Contributions Agreement") with MPLX GP LLC ("MPLX GP"), MPLX Logistics Holdings LLC ("MPLX Logistics"), MPLX Holdings Inc. ("MPLX Holdings") and MPC Investment LLC ("MPC Investment"), each a wholly-owned subsidiary of MPC, whereby the Partnership agreed to acquire certain ownership interests in joint venture entities indirectly held by MPC. Pursuant to the September 2017 Contributions Agreement, MPC Investment agreed to contribute: all of the membership interests of Lincoln Pipeline LLC, which holds a 35 percent interest in Illinois Extension; all of the membership interests of MPL Louisiana Holdings LLC, which holds a 41 percent interest in LOOP; a 59 percent interest in LOCAP; and a 25 percent interest in Explorer, through a series of intercompany contributions to the Partnership for an agreed upon purchase price of approximately \$420 million in cash and equity consideration valued at approximately \$630 million, for total consideration of \$1.05 billion (collectively, the "Joint-Interest Acquisition"). The number of common units representing the equity consideration was then determined by dividing the contribution amount by the simple average of the ten day trading volume weighted average NYSE price of a common unit for the ten trading days ending at market close on August 31, 2017. The fair value of the common and general partner units issued was approximately \$653 million based on the closing common unit price as of September 1, 2017, as recorded on the Consolidated Statements of Equity, for a total purchase price of \$1.07 billion. The equity issued consisted of: (i) 13,719,017 common units to MPLX GP, (ii) 3,350,893 common units to MPLX Logistics and (iii) 1,441,224 common units to MPLX Holdings. The Partnership also issued 377,778 general partner units to MPLX GP in order to maintain its two percent general partner interest ("GP Interest") in the Partnership.

Illinois Extension operates the 168-mile, 24-inch diameter Southern Access Extension ("SAX") crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, as well as additional tankage and two pump stations. LOOP owns and operates midstream crude oil infrastructure, including a deep water oil port offshore of Louisiana, pipelines and onshore storage facilities. LOOP also manages the operations of LOCAP, an affiliate pipeline. LOCAP owns and operates a crude oil pipeline and tank facility in St. James, Louisiana, which distributes oil received from LOOP's storage facilities and other connecting pipelines to nearby refineries and into the mid-continent region of the United States. Explorer owns and operates an approximate 1,830-mile common carrier pipeline that primarily transports gasoline, diesel, diluent and jet fuel from the Gulf Coast refining complex to the Midwest United States. The Partnership accounts for the Joint-Interest Acquisition entities as equity method investments within its L&S segment.

As a transfer between entities under common control, the Partnership recorded the Joint-Interest Acquisition on its Consolidated Balance Sheets at MPC's historical basis, which included accumulated other comprehensive loss. The Partnership recognizes an accumulated other comprehensive loss on its Consolidated Balance Sheets relating to pension and other post-retirement benefits provided by the LOOP and Explorer joint-interests to their employees. MPLX LP is not a sponsor of these benefit plans. There were no changes to *Accumulated other comprehensive loss* during the period September 1, 2017 through December 31, 2017.

Distributions of cash received from the entities and interests acquired in the Joint-Interest Acquisition related to periods prior to the acquisition will be prorated on a daily basis with MPLX LP retaining the portion of distributions beginning on the closing date. All amounts distributed to MPLX LP related to periods before the acquisition will be paid to MPC. Additionally, MPLX LP has agreed to pay MPC for any distributions of cash from LOOP related to the sale of LOOP's excess crude oil inventory. Because the future distributions or

payments cannot be reasonably quantified, a liability was not recorded in connection with the acquisition. MPLX LP subsequently received distributions related to the time period prior to the acquisition and recorded a liability to MPC and a corresponding decrease to the general partner's equity for \$32 million, as shown on the Consolidated Statements of Equity.

The Partnership accounts for the interests acquired in the Joint-Interest Acquisition in arrears using the most recently available information. The amount of income (loss) associated with these investments included in the Consolidated Statements of Income under the caption *Income (loss) from equity method investments* for the four months ended December 31, 2017 totaled \$21 million. MPC agreed to waive approximately two-thirds of the third quarter 2017 distributions on the common units issued in connection with the Joint-Interest Acquisition. As a result of this waiver, MPC did not receive approximately two-thirds of the distributions or IDRs that would have otherwise accrued on such common units with respect to the third quarter 2017 distributions. The value of these waived distributions was \$10 million.

#### ***Acquisition of Hardin Street Transportation LLC, Woodhaven Cavern LLC and MPLX Terminals LLC***

MPC contributed the assets of HST, WHC and MPLXT to newly created and wholly-owned subsidiaries and entered into commercial agreements related to services provided by these new entities to MPC on January 1, 2015 for HST and WHC and April 1, 2016 for MPLXT. Pursuant to a Membership Interests Contributions Agreement entered into on March 1, 2017, by the Partnership with MPLX GP, MPLX Logistics, MPLX Holdings and MPC Investment, each a wholly-owned subsidiary of MPC, MPC Investment agreed to contribute the outstanding membership interests in HST, WHC and MPLXT through a series of intercompany contributions to the Partnership for approximately \$1.5 billion in cash and equity consideration valued at approximately \$504 million (the "Transaction"). The number of common units representing the equity consideration was determined by dividing the contribution amount by the simple average of the ten day trailing volume weighted average NYSE price of a common unit for the ten trading days ending at market close on February 28, 2017. The fair value of the common and general partner units issued was approximately \$503 million, as recorded on the Consolidated Statements of Equity, and consisted of (i) 9,197,900 common units to MPLX GP, (ii) 2,630,427 common units to MPLX Logistics and (iii) 1,132,049 common units to MPLX Holdings. The Partnership also issued 264,497 general partner units to MPLX GP in order to maintain its two percent GP Interest in the Partnership. MPC agreed to waive two-thirds of the first quarter 2017 distributions on the common units issued in connection with the Transaction. As a result of this waiver, MPC did not receive two-thirds of the general partner distributions or IDRs that would have otherwise accrued on such common units with respect to the first quarter 2017 distributions. The value of these waived distributions was \$6 million.

HST owns and operates various crude oil and refined product pipelines and associated storage tanks. As of the acquisition date, these pipelines consisted of 174 miles of crude oil pipelines and 430 miles of refined products pipelines. WHC owns and operates eight butane and propane storage caverns located in Michigan with approximately 1.8 million barrels of NGL storage capacity. As of the acquisition date, MPLXT owned and operated 59 terminals for the receipt, storage, blending, additization, handling and redelivery of refined petroleum products. Additionally, MPLXT operated one leased terminal and had partial ownership interest in two terminals. Collectively, these 62 terminals had a combined shell capacity of approximately 23.6 million barrels as of the acquisition date. The terminal facilities are located primarily in the Midwest, Gulf Coast and Southeast regions of the United States. The Partnership accounts for these businesses within its L&S segment.

The Partnership retrospectively adjusted the historical financial results for all periods to give effect to the acquisition of HST and WHC effective January 1, 2015, and the acquisition of MPLXT effective April 1, 2016, as required for transactions between entities under common control. Prior to these dates, these entities were not considered businesses and, therefore, there are no financial results from which to recast.

### ***Acquisition of Ozark Pipeline***

On March 1, 2017, the Partnership acquired the Ozark pipeline from Enbridge Pipelines (Ozark) LLC for approximately \$219 million, including purchase price adjustments made in the second quarter of 2017. Based on the final fair value estimates of assets acquired and liabilities assumed at the acquisition date, the purchase price was primarily allocated to property, plant and equipment. The Ozark pipeline is a 433-mile, 22-inch crude oil pipeline originating in Cushing, Oklahoma, and terminating in Wood River, Illinois, capable of transporting approximately 230 mbpd. The Partnership accounts for the Ozark pipeline within its L&S segment.

The amounts of revenue and income from operations associated with the acquisition included in the Consolidated Statements of Income, since the March 1, 2017 acquisition date, are as follows:

<u>(In millions)</u>	<u>Ten Months Ended December 31, 2017</u>
Revenues and other income	\$64
Income from operations	20

Assuming the acquisition of the Ozark pipeline had occurred on January 1, 2016, the consolidated pro forma results would not have been materially different from reported results.

### ***MarEn Bakken***

On February 15, 2017, the Partnership closed on a joint venture, MarEn Bakken Company, LLC (“MarEn Bakken”), with Enbridge Energy Partners L.P. in which MPLX LP acquired a partial, indirect interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Company Pipeline projects, collectively referred to as the Bakken Pipeline system, from Energy Transfer Partners, L.P. and Sunoco Logistics Partners, L.P. The Partnership contributed \$500 million of the \$2.0 billion purchase price paid by MarEn Bakken to acquire a 36.75 percent indirect interest in the Bakken Pipeline system. The Partnership holds, through a subsidiary, a 25 percent interest in MarEn Bakken, which equates to a 9.1875 percent indirect interest in the Bakken Pipeline system.

The Partnership accounts for its investment in MarEn Bakken as an equity method investment and bases the equity method accounting for this joint venture in arrears using the most recently available information. The amount of income (loss) associated with these investments included in the Consolidated Statements of Income under the caption *Income (loss) from equity method investments* for the year ended December 31, 2017 totaled \$15 million. In connection with the Partnership’s acquisition of a partial, indirect equity interest in the Bakken Pipeline system, MPC agreed to waive its right to receive incentive distributions of \$1.6 million per quarter for twelve consecutive quarters, beginning with distributions declared in the first quarter of 2017 and paid to MPC in the second quarter of 2017, which was prorated to \$0.8 million from the acquisition date. This waiver is no longer applicable as a result of the GP IDR Exchange on February 1, 2018.

### ***Acquisition of Hardin Street Marine LLC***

On March 14, 2016, the Partnership entered into a Membership Interests Contribution Agreement (the “Contribution Agreement”) with MPLX GP, MPLX Logistics and MPC Investment, each a wholly-owned subsidiary of MPC, related to the acquisition of HSM, MPC’s inland marine business, from MPC. Pursuant to the Contribution Agreement, the transaction was valued at \$600 million, consisting of a fixed number of common units and general partner units of 22,534,002 and 459,878, respectively. The general partner units maintain MPC’s two percent GP Interest in the Partnership. The acquisition closed on March 31, 2016 and the fair value of the common units and general partner units issued was \$669 million and \$14 million, respectively, as recorded on the Consolidated Statements of Equity. MPC agreed to waive distributions in the first quarter of 2016 on common units issued in connection with this transaction. As a result of this waiver, MPC did not receive general partner distributions or IDRs that would have otherwise accrued on such common units with respect to the first quarter 2016 distributions. The value of these waived distributions was \$15 million.



The inland marine business, comprised of 18 tow boats and 219 owned and leased barges as of the acquisition date, which transport light products, heavy oils, crude oil, renewable fuels, chemicals and feedstocks in the Midwest and Gulf Coast regions of the United States, accounted for nearly 60 percent of the total volumes MPC shipped by inland marine vessels as of March 31, 2016. The Partnership accounts for HSM within its L&S segment.

***Purchase of MarkWest Energy Partners, L.P.***

On December 4, 2015, a wholly-owned subsidiary of the Partnership merged with MarkWest. Each common unit of MarkWest issued and outstanding immediately prior to the effective time of the MarkWest Merger was converted into a right to receive 1.09 common units representing limited partner interests in MPLX LP, plus a one-time cash payment of \$6.20 per unit. Each Class B unit of MarkWest issued and outstanding immediately prior to the effective time of the MarkWest Merger was converted into the right to receive one Class B unit of MPLX LP. The Class B units of MPLX LP automatically converted, in two equal installments, into 1.09 common units of MPLX LP and the right to receive \$6.20 in cash, on July 1, 2016 and July 1, 2017. MPC contributed approximately \$1.3 billion of cash to the Partnership to pay the aggregate cash consideration to MarkWest unitholders, without receiving any new equity in exchange. At closing, MPC made a payment of \$1.2 billion to MarkWest common unitholders and the remaining \$50 million was paid, in equal amounts, during July 2016 and July 2017, in connection with the conversion of the remaining outstanding Class B units to MPLX LP common units. The Partnership's financial results reflect the results of MarkWest from the date of the acquisition.

The components of the fair value of consideration transferred was as follows:

<i>(In millions)</i>	
Fair value of units issued	\$7,326
Cash	1,230
Paid to MarkWest Class B unitholders	<u>50</u>
Total fair value of consideration transferred	<u>\$8,606</u>

The following table summarizes the final purchase price allocation. Subsequent to December 31, 2015, additional analysis was completed and adjustments were made to the preliminary purchase price allocation as noted in the table below. The fair value of assets acquired and liabilities and noncontrolling interests assumed at the acquisition date as of December 31, 2016, was as follows:

<u>(In millions)</u>	<u>As Originally Reported</u>	<u>Adjustments</u>	<u>As Adjusted</u>
Cash and cash equivalents	\$ 12	\$ —	\$ 12
Receivables	164	—	164
Inventories	33	(1)	32
Other current assets	44	—	44
Equity method investments	2,457	143	2,600
Property, plant and equipment	8,474	43	8,517
Intangibles	468	65	533
Other noncurrent assets	5	—	5
Total assets acquired	<u>11,657</u>	<u>250</u>	<u>11,907</u>
Accounts payable	322	—	322
Accrued liabilities	13	6	19
Accrued taxes	21	—	21
Other current liabilities	44	—	44
Long-term debt	4,567	—	4,567
Deferred income taxes	374	3	377
Deferred credits and other liabilities	151	—	151
Noncontrolling interests	13	—	13
Total liabilities and noncontrolling interests assumed	<u>5,505</u>	<u>9</u>	<u>5,514</u>
Net assets acquired excluding goodwill	6,152	241	6,393
Goodwill	2,454	(241)	2,213
Net assets acquired	<u>\$ 8,606</u>	<u>\$ —</u>	<u>\$ 8,606</u>

Adjustments to the preliminary purchase price stem mainly from additional information obtained by management in the first and second quarters of 2016 about facts and circumstances that existed at the acquisition date, including updates to forecasted employee benefit costs, maintenance capital expenditures and completion of certain valuations to determine the underlying fair value of certain acquired assets. The adjustment to intangibles mainly related to a misstatement in the original preliminary purchase price allocation, resulting in a \$68 million reduction to the carrying value of goodwill and an offsetting increase of \$64 million in intangibles, \$2 million in equity method investments and \$2 million in property, plant and equipment. Management concluded that the correction of the error was immaterial to the consolidated financial statements. As further discussed in Note 18, in the first quarter of 2016 the Partnership recorded a goodwill impairment charge based on the implied fair value of goodwill as of the interim impairment analysis date. During the second quarter of 2016, the Partnership finalized its analysis of the final purchase price allocation. The completion of the purchase price allocation resulted in a refinement of the impairment expense recorded, as more fully discussed in Note 18.

The increase to the fair value of intangibles and property, plant and equipment noted above resulted in additional amortization and depreciation expense of approximately \$1 million recognized for the year ended December 31, 2016, in *Depreciation and amortization* in the Consolidated Statements of Income, that would have been recorded for the year ended December 31, 2015, had the fair value adjustments been recorded as of December 4, 2015. The increase in the fair value of equity investments above would not have had a material effect on the income from equity method investments had the fair value adjustment been recorded as of December 4, 2015.

The purchase price allocation resulted in the recognition of \$2.2 billion of goodwill in three reporting units within the Partnership's G&P segment, substantially all of which is not deductible for tax purposes. Goodwill

represents the complimentary aspects of the highly diverse asset base of MarkWest and MPLX LP that provides significant additional opportunities across multiple segments of the hydrocarbon value chain.

The Partnership recognized \$36 million of acquisition-related costs associated with the MarkWest Merger. These costs were expensed, with \$30 million included in *General and administrative expenses* and \$6 million included in *Other financial costs*.

The fair value of the common units issued was determined on the basis of the closing market price of the Partnership's units as of the effective time of the transaction and is considered a Level 1 measurement. The fair value of the Class B units issued was determined based on reference to the value of the common units, adjusted for a lack of distributions prior to their stated conversion dates, and is considered a Level 2 measurement. The fair values of the long-term debt and SMR liabilities were determined as of the acquisition date using the methods discussed in Note 15.

The fair value of the equity method investments was determined based on applying the discounted cash flow method, which is an income approach, to the Partnership's equity method investments on an individual basis. Key assumptions included discount rates of 9.4 percent to 11.1 percent and terminal values based on the Gordon growth method to capitalize the cash flows, using a 2.5 percent long-term growth rate. Intangibles represented customer contracts and related relationships. The fair value of the intangibles was determined based on applying the multi-period excess earnings method, which is an income approach. Key assumptions included attrition rates by reporting unit ranging from 5.0 percent to 10.0 percent and discount rates by reporting unit ranging from 11.5 percent to 12.8 percent. The fair value of property, plant and equipment was determined primarily based on the cost approach. Key assumptions included inputs to the valuation methodology such as recent purchases of similar items and published data for similar items. Components were adjusted for economic and functional obsolescence, location, normal useful lives, and capacity (if applicable). The fair value measurements for equity method investments, intangibles and property, plant and equipment were based on significant inputs that were not observable in the market and, therefore, represent Level 3 measurements.

The amounts of revenue and income from operations associated with MarkWest in the Consolidated Statements of Income for 2015 were as follows:

<u>(In millions)</u>	<u>2015</u>
Revenues and other income	\$126
Income from operations	32

### ***Unaudited Pro Forma Financial Information***

The following unaudited pro forma financial information presents consolidated results assuming the MarkWest Merger occurred on January 1, 2014.

<u>(In millions, except per unit data)</u>	<u>2015</u>
Revenues and other income	\$2,817
Net income attributable to MPLX LP	228
Net income attributable to MPLX LP per unit—basic	0.47
Net income attributable to MPLX LP per unit—diluted	0.45

The unaudited pro forma financial information includes adjustments primarily to align accounting policies, adjust depreciation expense to reflect the fair value of property, plant and equipment, increase amortization expense related to identifiable intangible assets and adjust interest expense related to the fair value of MarkWest's long-term debt, as well as the related income tax effects. The pro forma financial information does not give effect to potential synergies that could result from the acquisition and is not necessarily indicative of the results of future operations.

MarkWest had a 60 percent legal ownership interest in MarkWest Utica EMG, L.L.C. (“MarkWest Utica EMG”) for the year ended December 31, 2015. MarkWest Utica EMG’s inability to fund its planned activities without subordinated financial support qualify it as a VIE. The financing structure for MarkWest Utica EMG at its inception resulted in a de-facto agent relationship under which MarkWest was deemed to be the primary beneficiary of MarkWest Utica EMG. Therefore, MarkWest consolidated MarkWest Utica EMG in its historical financial statements. In the fourth quarter of 2015, based on economic conditions and other pertinent factors, the accounting for its investment in MarkWest Utica EMG was reassessed. As of December 4, 2015, the entity has been deconsolidated. For purposes of this pro forma financial information, MarkWest Utica EMG has been consolidated for the period prior to the acquisition consistent with its treatment in the historical periods presented.

The following table is a summary of the amounts included in the historical financial statements of MarkWest for the period from January 1, 2015 through December 3, 2015 related to MarkWest Utica EMG:

<u>(in millions)</u>	<u>2015</u>
Revenues and other income	\$152
Cost of revenue excluding depreciation and amortization	27
Depreciation and amortization	61
Net income attributable to noncontrolling interests	64
Net loss	(5)

EMG Utica, LLC (“EMG Utica”), a joint venture partner in MarkWest Utica EMG, received a special non-cash allocation of income of approximately \$41 million for the period from January 1, 2015 through December 3, 2015. See Note 5 for a description of the transaction and its impact on the financial statements. Net income of MarkWest would not have changed had MarkWest Utica EMG been deconsolidated for the period from January 1, 2015 through December 3, 2015.

### ***Purchase of Pipe Line Holdings***

Effective December 4, 2015, the Partnership purchased the remaining 0.5 percent interest in MPLX Pipe Line Holdings LLC (“Pipe Line Holdings”) from subsidiaries of MPC for consideration of \$12 million. This resulted in Pipe Line Holdings becoming a wholly-owned subsidiary of the Partnership. The Partnership recorded the 0.5 percent interest at its historical carrying value of \$6 million and the excess cash paid and equity contributed over historical carrying value of \$6 million as a decrease to general partner equity. Prior to this transaction, the 0.5 percent interest was held by MPC and was reflected as the noncontrolling interest retained by MPC in the consolidated financial statements. There was no material change to MPLX LP’s equity resulting from this transaction.

## 5. Investments and Noncontrolling Interests

The following table presents the Partnership's equity method investments at the dates indicated:

<i>(In millions)</i>	Ownership as of December 31, 2017	Carrying value at December 31,	
		2017	2016
Centrahoma Processing LLC	40%	\$ 121	\$ 104
Explorer	25%	89	—
Illinois Extension Pipeline	35%	284	—
LOCAP	59%	24	—
LOOP	41%	225	—
MarEn Bakken	25%	520	—
MarkWest EMG Jefferson Dry Gas Gathering Company, LLC	67%	164	67
MarkWest Utica EMG, L.L.C.	56%	2,139	2,224
Ohio Condensate Company, L.L.C.	60%	11	10
Panola Pipeline Company, L.L.C.	15%	24	25
Sherwood Midstream LLC	50%	236	—
Sherwood Midstream Holdings LLC	69%	165	—
Other		8	41
Total		<u>\$4,010</u>	<u>\$2,471</u>

The following tables present summarized financial information for the Partnership's equity method investments for the years ended December 31, 2017, 2016 and from the date of the MarkWest Merger through December 31, 2015:

<i>(In millions)</i>	Year Ended December 31, 2017			
	MarkWest Utica EMG	Other VIEs	Non-VIEs	Total
Revenues and other income	\$187	\$86	\$954	\$1,227
Costs and expenses	97	42	520	659
Income from operations	90	44	434	568
Net income	90	43	345	478
Income from equity method investments <sup>(1)</sup>	10	20	48	78

<i>(In millions)</i>	Year Ended December 31, 2016			
	MarkWest Utica EMG	Other VIEs <sup>(2)</sup>	Non-VIEs	Total
Revenues and other income	\$216	\$ 18	\$148	\$382
Costs and expenses	100	111	117	328
Income (loss) from operations	116	(93)	31	54
Net income (loss)	114	(93)	31	52
Income (loss) from equity method investments <sup>(1)</sup>	8	(89)	7	(74)

<i>(In millions)</i>	Period Ended December 31, 2015			
	MarkWest Utica EMG	Other VIEs	Non-VIEs	Total
Revenues and other income	\$18	\$ 2	\$ 9	\$29
Costs and expenses	9	2	8	19
Income from operations	9	—	1	10
Net income	10	—	1	11
Income from equity method investments <sup>(1)</sup>	2	1	—	3

- (1) *Income (loss) from equity method investments* includes the impact of any basis differential amortization or accretion.
- (2) Includes an impairment charge of \$89 million for the year ended December 31, 2016 related to the Partnership's investment in Ohio Condensate Company, L.L.C. ("Ohio Condensate"), which does not appear separately in this table.

The following tables present summarized balance sheet information for the Partnership's equity method investments as of December 31, 2017 and 2016:

<i>(In millions)</i>	December 31, 2017			
	MarkWest Utica EMG <sup>(1)</sup>	Other VIEs	Non-VIEs	Total
Current assets	\$ 65	\$ 46	\$ 399	\$ 510
Noncurrent assets	2,077	930	4,624	7,631
Current liabilities	39	44	220	303
Noncurrent liabilities	3	11	904	918

<i>(In millions)</i>	December 31, 2016			
	MarkWest Utica EMG <sup>(1)</sup>	Other VIEs	Non-VIEs	Total
Current assets	\$ 45	\$ 2	\$ 40	\$ 87
Noncurrent assets	2,173	132	390	2,695
Current liabilities	30	4	26	60
Noncurrent liabilities	2	13	—	15

- (1) MarkWest Utica EMG noncurrent assets include its investment in its subsidiary Ohio Gathering Company, L.L.C. ("Ohio Gathering"), which does not appear elsewhere in this table. The investment was \$790 million and \$794 million as of December 31, 2017 and 2016, respectively.

As of December 31, 2017, the carrying value of the Partnership's equity method investments exceeded the underlying net assets of its investees by \$1.0 billion. This basis difference is being amortized or accreted into net income over the remaining estimated useful lives of the underlying net assets, except for \$459 million of excess related to goodwill.

### ***MarkWest Utica EMG***

Effective January 1, 2012, MarkWest Utica Operating Company, LLC ("Utica Operating"), a wholly-owned and consolidated subsidiary of MarkWest, and EMG Utica, LLC ("EMG Utica" and together with Utica Operating, the "Members") executed agreements to form a joint venture, MarkWest Utica EMG, to develop significant natural gas gathering, processing and NGL fractionation, transportation and marketing infrastructure in eastern Ohio. The related limited liability company agreement has been amended from time to time (the limited liability company agreement currently in effect is referred to as the "Amended LLC Agreement"). The aggregate funding commitment of EMG Utica was \$950 million. Thereafter, Utica Operating was required to fund, as needed, 100 percent of future capital for MarkWest Utica EMG until the aggregate capital that had been contributed by the Members reached \$2.0 billion, which occurred prior to the MarkWest Merger. Until such time as the investment balances of Utica Operating and EMG Utica are in the ratio of 70 percent and 30 percent, respectively (such time being referred to as the "Second Equalization Date"), EMG Utica will have the right, but not the obligation, to fund up to 10 percent of each capital call for MarkWest Utica EMG, and Utica Operating will be required to fund all remaining capital not elected to be funded by EMG Utica. After the Second Equalization Date, Utica Operating and EMG Utica will have the right, but not the obligation, to fund their pro rata portion (based on their respective investment balances) of any additional required capital and may also fund additional capital that the other party elects not to fund. As of December 31, 2017, EMG Utica has contributed approximately \$1.2 billion and Utica Operating has contributed approximately \$1.5 billion to MarkWest Utica EMG.

Under the Amended LLC Agreement, prior to December 31, 2016, EMG Utica's investment balance was increased by a quarterly special non-cash allocation of income ("Preference Amount") calculated based upon the amount of capital contributed by EMG Utica in excess of \$500 million. After December 31, 2016, no Preference Amount will accrue to EMG Utica's investment balance. EMG Utica received a Preference Amount totaling approximately \$16 million for the year ended December 31, 2016 and \$4 million for the 28 days ended December 31, 2015.

Under the Amended LLC Agreement, after December 31, 2016, cash generated by MarkWest Utica EMG that is available for distribution will be allocated to the Members in proportion to their respective investment balances. As of December 31, 2017, Utica Operating's investment balance in MarkWest Utica EMG was approximately 56 percent.

MarkWest Utica EMG is deemed to be a VIE. Utica Operating is not deemed to be the primary beneficiary, due to EMG Utica's voting rights on significant matters. The Partnership's maximum exposure to loss as a result of its involvement with MarkWest Utica EMG includes its equity investment, any additional capital contribution commitments and any operating expenses incurred by the subsidiary operator in excess of its compensation received for the performance of the operating services. The Partnership did not provide any financial support to MarkWest Utica EMG that it was not contractually obligated to provide during the years ended December 31, 2017, 2016 and the 28 days ended December 31, 2015. The Partnership receives management fee revenue for engineering and construction and administrative services for operating MarkWest Utica EMG, and is also reimbursed for personnel services ("Operational Service revenue"). Operational Service revenue is reported as *Other income—related parties* in the Consolidated Statements of Income. The amount of Operational Service revenue related to MarkWest Utica EMG for the years ended December 31, 2017, 2016, and the 28 days ended December 31, 2015 totaled \$17 million, \$16 million, and less than \$1 million, respectively.

### ***Ohio Gathering***

Ohio Gathering is a subsidiary of MarkWest Utica EMG and is engaged in providing natural gas gathering services in the Utica Shale in eastern Ohio. Ohio Gathering is a joint venture between MarkWest Utica EMG and Summit Midstream Partners, LLC. As of December 31, 2017, the Partnership had an approximate 34 percent indirect ownership interest in Ohio Gathering. As Ohio Gathering is a subsidiary of MarkWest Utica EMG, which is accounted for as an equity method investment, the Partnership reports its portion of Ohio Gathering's net assets as a component of its investment in MarkWest Utica EMG. The Partnership receives Operational Service revenue for operating Ohio Gathering which is reported as *Other income-related parties* in the Consolidated Statements of Income. The amount of Operational Service revenue related to Ohio Gathering for the years ended December 31, 2017, 2016 and the 28 days ended December 31, 2015 totaled \$16 million, \$15 million, and \$2 million, respectively.

### ***Ohio Condensate***

Ohio Condensate Company, L.L.C. ("Ohio Condensate") is a joint venture between MarkWest Utica EMG Condensate, L.L.C., a wholly-owned and consolidated subsidiary of MarkWest, and Summit. The Partnership accounts for Ohio Condensate, which is a VIE, as an equity method investment as MPLX LP exercises significant influence, but does not control Ohio Condensate and is not its primary beneficiary due to Summit's voting rights on significant matters. During the second quarter of 2016, forecasts for Ohio Condensate were reduced to align with updated forecasts for customer requirements. As the operator of that entity responsible for maintaining its financial records, the Partnership completed a fixed asset impairment analysis as of June 30, 2016, in accordance with ASC Topic 360, to determine the potential fixed asset impairment charge. The resulting fixed asset impairment charge recorded within Ohio Condensate's financial statements was \$96 million. Based on the Partnership's 60 percent ownership of Ohio Condensate, approximately \$58 million was recorded in the second quarter of 2016 in *(Loss) income from equity method investments* on the accompanying Consolidated Statements of Income.

The Partnership's investment in Ohio Condensate, which was established at fair value in connection with the MarkWest Merger, exceeded its proportionate share of the underlying net assets. Therefore, in conjunction with the ASC Topic 360 impairment analysis, the Partnership completed an equity method impairment analysis in accordance with ASC Topic 323 to determine the potential additional equity method impairment charge to be recorded on the Partnership's consolidated financial statements resulting from an other-than-temporary impairment. As a result, an additional impairment charge of approximately \$31 million was recorded in the second quarter of 2016 in *(Loss) income from equity method investments* on the accompanying Consolidated Statements of Income, which eliminated the basis differential established in connection with the MarkWest Merger.

The fair value of Ohio Condensate and its underlying fixed assets was determined based upon applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The discounted cash flow fair value estimate is based on known or knowable information at the interim measurement date. The significant assumptions that were used to develop the estimate of the fair value under the discounted cash flow method include management's best estimates of the expected future results using a probability-weighted average set of cash flow forecasts and a discount rate of 11.2 percent. An increase to the discount rate of 50 basis points would have resulted in an additional charge of \$1 million on the Consolidated Statements of Income. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As such, the fair value of the Ohio Condensate equity method investment and its underlying fixed assets represents a Level 3 measurement. As a result, there can be no assurance that the estimates and assumptions made for purposes of the interim impairment test will prove to be an accurate prediction of the future.

### ***Sherwood Midstream***

Effective January 1, 2017, MarkWest Liberty Midstream & Resources, L.L.C. ("MarkWest Liberty Midstream"), a wholly-owned and consolidated subsidiary of MarkWest, and Antero Midstream Partners LP ("Antero Midstream") formed a joint venture, Sherwood Midstream LLC ("Sherwood Midstream"), to support Antero Resources' development in the Marcellus Shale. MarkWest Liberty Midstream has a 50 percent ownership interest in Sherwood Midstream. Pursuant to the terms of the related limited liability company agreement (the "LLC Agreement"), MarkWest Liberty Midstream contributed assets then under construction with a fair value of approximately \$134 million and cash of approximately \$20 million. Antero Midstream made an initial capital contribution of approximately \$154 million.

Also effective January 1, 2017, MarkWest Liberty Midstream converted all of its ownership interests in MarkWest Ohio Fractionation Company, L.L.C. ("Ohio Fractionation"), a previously wholly-owned subsidiary, to Class A Interests and amended its LLC Agreement to create Class B-3 Interests, which were sold to Sherwood Midstream for \$126 million in cash. The Class B-3 Interests provide Sherwood Midstream with the right to fractionation revenue and the obligation to pay expenses related to 20 mbpd of capacity in the Hopedale 3 fractionator. Sherwood Midstream accounts for its investment in Ohio Fractionation, which is a VIE, as an equity method investment as Sherwood Midstream does not control Ohio Fractionation. MarkWest Liberty Midstream has been deemed to be the primary beneficiary of Ohio Fractionation because it has control over the decisions that could significantly impact its financial performance, and as a result, consolidates Ohio Fractionation. The carrying amounts of assets and liabilities included in the Partnership's Consolidated Balance Sheets pertaining to Ohio Fractionation at December 31, 2017, were current assets of \$63 million, non-current assets of \$405 million and current liabilities of \$14 million. The creditors of Ohio Fractionation do not have recourse to MPLX LP's general credit through guarantees or other financial arrangements. The assets of Ohio Fractionation are the property of Ohio Fractionation and cannot be used to satisfy the obligations of MPLX LP. Sherwood Midstream's interests are reflected in *Net income attributable to noncontrolling interests* in the Consolidated Statements of Income and *Noncontrolling interests* in the Consolidated Balance Sheets.

Under the LLC Agreement, cash generated by Sherwood Midstream that is available for distribution will be allocated to the members in proportion to their respective investment balances.



Sherwood Midstream is deemed to be a VIE. MarkWest Liberty Midstream is not deemed to be the primary beneficiary, due to Antero Midstream's voting rights on significant matters. The Partnership's maximum exposure to loss as a result of its involvement with Sherwood Midstream includes its equity investment, any additional capital contribution commitments and any operating expenses incurred by the subsidiary operator in excess of its compensation received for the performance of the operating services. The Partnership did not provide any financial support to Sherwood Midstream that it was not contractually obligated to provide during the year ended December 31, 2017. The Partnership receives Operational Service revenue for operating Sherwood Midstream. The amount of Operational Service revenue related to Sherwood Midstream for the year ended December 31, 2017 totaled approximately \$8 million and is reported as *Other income-related parties* in the Consolidated Statements of Income.

### ***Sherwood Midstream Holdings***

Effective January 1, 2017, MarkWest Liberty Midstream and Sherwood Midstream formed a joint venture, Sherwood Midstream Holdings LLC ("Sherwood Midstream Holdings"), for the purpose of owning, operating and maintaining all of the shared assets that support the operations of the gas plants and other assets owned by Sherwood Midstream and the gas plants and deethanization facilities owned by MarkWest Liberty Midstream. MarkWest Liberty Midstream initially contributed certain real property, equipment and facilities with a fair value of approximately \$209 million to Sherwood Midstream Holdings in exchange for a 79 percent initial ownership interest. Sherwood Midstream contributed cash of approximately \$44 million to Sherwood Midstream Holdings in exchange for a 21 percent ownership interest. During the second quarter ended June 30, 2017, true-ups to the initial contributions were finalized. MarkWest Liberty Midstream contributed certain additional real property, equipment and facilities with a fair value of approximately \$10 million to Sherwood Midstream Holdings and Sherwood Midstream contributed cash of approximately \$4 million to Sherwood Midstream Holdings. Collectively, the real property, equipment, facilities and cash initially contributed, or that may be subsequently constructed by or contributed, to Sherwood Midstream Holdings are referred to as the "Shared Assets." The net book value of the contributed assets was approximately \$203 million. The contribution was determined to be an in-substance sale of real estate. As such, the Partnership only recognized a gain for the portion attributable to Antero Midstream's indirect interest of approximately \$2 million, included in *Gain on sale of assets* in the Consolidated Statements of Income. MarkWest Liberty Midstream's portion of the gain attributable to its direct and indirect interests of approximately \$14 million is included in its investment in Sherwood Midstream Holdings and is reported under the caption *Equity method investments* on the Consolidated Balance Sheets. In connection with the initial contributions, MarkWest Liberty Midstream received a special distribution of approximately \$45 million.

MarkWest Liberty Midstream's and Sherwood Midstream's ownership interests in Sherwood Midstream Holdings will fluctuate over time. As new Shared Assets are constructed, the members will make additional capital contributions to Sherwood Midstream Holdings. The amount that each member must contribute will be based on the expected utilization of the Shared Assets, as defined in the LLC Agreement. Pursuant to the terms of the LLC Agreement, MarkWest Liberty Midstream will serve as the operator for Sherwood Midstream Holdings.

The Partnership accounts for Sherwood Midstream Holdings, which is a VIE, as an equity method investment as Sherwood Midstream is considered to be the general partner and controls all decisions. The Partnership's maximum exposure to loss as a result of its involvement with Sherwood Midstream Holdings includes its equity investment, any additional capital contribution commitments and any operating expenses incurred by the subsidiary operator in excess of its compensation received for the performance of operating services. The Partnership did not provide any financial support to Sherwood Midstream Holdings that it was not contractually obligated to provide during the year ended December 31, 2017.

Sherwood Midstream has been deemed the primary beneficiary of Sherwood Midstream Holdings due to its controlling financial interest through its authority to manage the joint venture. As a result, Sherwood Midstream consolidates Sherwood Midstream Holdings. Therefore, the Partnership also reports its portion of Sherwood Midstream Holdings' net assets as a component of its investment in Sherwood Midstream. As of December 31,

2017, the Partnership has a 15.7 percent indirect ownership interest in Sherwood Midstream Holdings through Sherwood Midstream.

## **6. Related Party Agreements and Transactions**

The Partnership's material related parties include:

- MPC, which refines, markets and transports crude oil and petroleum products, primarily in the Midwest, Gulf Coast, East Coast and Southeast regions of the United States.
- MarkWest Utica EMG, in which MPLX LP has a 56 percent interest as of December 31, 2017. MarkWest Utica EMG is engaged in natural gas processing and NGL fractionation, transportation and marketing in Ohio.
- Ohio Gathering, in which MPLX LP has a 34 percent indirect interest as of December 31, 2017. Ohio Gathering is a subsidiary of MarkWest Utica EMG providing natural gas gathering service in the Utica Shale region of eastern Ohio.
- Sherwood Midstream, in which MPLX LP has a 50 percent interest as of December 31, 2017. Sherwood Midstream supports the development of Antero Resources' Marcellus Shale acreage in the rich-gas corridor of West Virginia.
- Sherwood Midstream Holdings, in which MPLX LP has an 85 percent total direct and indirect interest as of December 31, 2017. Sherwood Midstream Holdings owns certain infrastructure at the Sherwood Complex that is shared by and supports the operation of both the Sherwood Midstream and MarkWest gas processing plants and deethanization facilities.
- MarkWest EMG Jefferson Dry Gas Gathering Company, L.L.C. ("Jefferson Dry Gas"), in which MPLX LP has a 67 percent interest as of December 31, 2017. Jefferson Dry Gas provides natural dry gas gathering and related services in the Utica Shale region of Ohio.

### ***Commercial Agreements***

The Partnership has various long-term, fee-based commercial agreements with MPC. Under these agreements, the Partnership provides transportation, terminal and storage services to MPC, and MPC has committed to provide the Partnership with minimum quarterly throughput volumes on crude oil and refined products systems, and minimum storage volumes of crude oil and refined products. MPC has also committed to provide a fixed fee for 100 percent of available capacity for boats, barges and third-party chartered equipment under the marine transportation service agreement. The Partnership believes the terms and conditions under these agreements, as well as the initial agreements with MPC described below, are generally no less favorable to either party than those that could have been negotiated with unaffiliated parties with respect to similar services.

As discussed in Note 4, the Partnership acquired HST, WHC and MPLXT on March 1, 2017, and HSM on March 14, 2016. HST, WHC, MPLXT and HSM have various operating, transportation services, terminal services, storage services, and employee services agreements with MPC, which were assumed by the Partnership with the closing of these transactions.

The commercial agreements with MPC include:

- *Transportation services agreements*—The Partnership has various separate transportation services agreements with terms ranging from five to 15 years, under which MPC pays the Partnership fees for transporting crude oil and refined products on various of the Partnership's crude oil and refined product pipelines. The Partnership also has a five-year agreement under which MPC pays the Partnership fees for handling crude oil and products at the Partnership's Wood River, Illinois barge dock, and a six-year transportation services agreement under which MPC pays the Partnership fees for providing marine transportation of crude oil, feedstocks and refined petroleum products, and related services.

All of the transportation services agreements include automatic renewal terms ranging from two to five years, unless terminated by either party. Under the terms of these agreements, with the exception of the marine agreement, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay the Partnership a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect (the “Quarterly Deficiency Payment”). The amount of any Quarterly Deficiency Payment paid by MPC may be applied as a credit for any volumes transported on the applicable pipeline in excess of MPC’s minimum volume commitment during any of the succeeding four quarters, or eight quarters in the case of the transportation services agreements covering the Wood River to Patoka crude pipeline and the Wood River barge dock, after which time any unused credits will expire. Upon the expiration or termination of a transportation services agreement, MPC will have the opportunity to apply any such remaining credit amounts until the completion of any such four-quarter or eight-quarter period, as applicable. Any such remaining credits may be used against any volumes shipped by MPC on the applicable pipeline, without regard to any minimum volume commitment that may have been in place during the term of the agreement.

- *Storage services agreements*—The Partnership has two storage services agreements, with 10-year and 17-year terms, respectively, under which MPC pays the Partnership fees for providing storage services at the Partnership’s Neal, West Virginia butane cavern and Woodhaven, Michigan butane and propane caverns. The Partnership also has various separate three-year storage services agreements under which MPC pays the Partnership fees for providing storage services at the Partnership’s tank farms, and various separate three-year storage services agreements under which MPC pays the Partnership fees for providing storage services at the Partnership’s storage tanks associated with the Partnership’s crude oil and refined product pipelines.

The Partnership’s butane cavern storage services agreement with MPC does not automatically renew, and the Partnership’s tank farm storage services agreements with MPC automatically renew for additional one-year terms unless terminated by either party. Under the terms of these agreements, the Partnership is obligated to make available to MPC, on a firm basis, the available storage capacity at MPLX LP’s tank farms and caverns. MPC pays the Partnership a per-barrel fee for such storage capacity, regardless of whether MPC fully utilizes the available capacity.

- *Terminal services agreement*—The Partnership has a 10-year terminal services agreement under which MPC pays the Partnership fees for terminal storage for refined petroleum products.

The terminal services agreement with MPC includes automatic renewal terms ranging from two to five years, unless terminated by either party. Under the terms of the agreement, MPC pays the Partnership monthly based on contractual fees relating to MPC product deliveries as well as any viscosity surcharges, loading, handling, transfers or other related charges. If MPC fails to meet its quarterly minimum volume throughput commitments, MPC will pay a deficiency payment equal to the volume of the deficiency multiplied by the rate then in effect. If the average daily capacity of a terminal falls below the level of MPC’s commitment during a quarter, depending on the cause of the reduction in capacity, MPC’s throughput commitment will be reduced to equal the average daily capacity available during such quarter.

### ***Operating Agreements***

The Partnership operates various pipelines owned by MPC under operating services agreements. Under these operating services agreements, the Partnership receives an operating fee for operating the assets and is reimbursed for all direct and indirect costs associated with operating the assets. Most of these agreements are indexed for inflation. These agreements range from one to five years in length and automatically renew unless terminated by either party.

### ***Management Services Agreement***

The Partnership, through its subsidiary, HSM, has a management services agreement with MPC under which it provides management services to assist MPC in the oversight and management of the marine business. HSM receives a fixed annual fee for providing the required management services. This fee is adjusted annually on the anniversary of the contract for inflation and any changes in the scope of the management services provided. This agreement is set to expire on January 1, 2021 and automatically renews for two additional renewal terms of five years each unless terminated by either party.

### ***Omnibus Agreement***

The Partnership has an omnibus agreement with MPC that addresses its payment of a fixed annual fee to MPC for the provision of executive management services by certain executive officers of the general partner and the Partnership's reimbursement of MPC for the provision of certain general and administrative services to it. It also provides for MPC's indemnification of the Partnership for certain matters, including environmental, title and tax matters; as well as our indemnification of MPC for certain matters under this agreement.

### ***Employee Services Agreements***

The Partnership has various employee services agreements with MPC under which the Partnership reimburses MPC for employee benefit expenses, along with the provision of operational and management services in support of both our L&S and G&P segments' operations, including those in support of HST, WHC, MPLXT and HSM.

### ***Loan Agreement***

On December 4, 2015, the Partnership entered into a loan agreement with MPC Investment LLC ("MPC Investment"), a wholly-owned subsidiary of MPC. Under the terms of the agreement, MPC Investment will make a loan or loans to the Partnership on a revolving basis as requested by the Partnership and as agreed to by MPC Investment, in an amount or amounts that do not result in the aggregate principal amount of all loans outstanding exceeding \$500 million at any one time. The entire unpaid principal amount of the loan, together with all accrued and unpaid interest and other amounts (if any), shall become due and payable on December 4, 2020. MPC Investment may demand payment of all or any portion of the outstanding principal amount of the loan, together with all accrued and unpaid interest and other amounts (if any), at any time prior to December 4, 2020. Borrowings under the loan will bear interest at LIBOR plus 1.50 percent. In connection with this loan agreement, the Partnership terminated the previous revolving credit agreement of \$50 million with MPC, effective December 31, 2015.

During 2017, the Partnership borrowed \$2.4 billion and repaid \$2.0 billion, resulting in a \$386 million outstanding balance at December 31, 2017, which is included in *Payables—related parties* on the Consolidated Balance Sheets. During 2016, the Partnership borrowed \$2.5 billion and repaid \$2.5 billion, resulting in no outstanding balance at December 31, 2016. Borrowings were at an average interest rate of 2.777 percent and 1.939 percent per annum for 2017 and 2016, respectively.

### ***Related Party Transactions***

The Partnership believes that transactions with related parties were conducted on terms comparable to those with unrelated parties. Related party sales to MPC consisted of crude oil and refined products pipeline transportation services based on regulated tariff rates, storage and terminal services based on contracted rates and marine transportation services. Related party sales to MPC also consist of revenue related to volume deficiency credits.

Revenue received from related parties related to service and product sales were as follows:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Service revenue			
MPC	\$1,082	\$936	\$701
Rental income			
MPC	\$ 279	\$235	\$146
Product sales <sup>(1)</sup>			
MPC	\$ 8	\$ 11	\$ 1

<sup>(1)</sup> For 2017, 2016, and 2015, there were \$254 million, \$46 million and \$1 million, respectively, of additional product sales to MPC that net to zero within the consolidated financial statements, as the transactions are recorded net due to the terms of the agreements under which such product was sold.

The revenue received from related parties included in *Other income—related parties* on the Consolidated Statements of Income, was as follows:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
MPC	\$40	\$ 45	\$ 55
MarkWest Utica EMG	17	16	—
Ohio Gathering	16	15	2
Jefferson Dry Gas	6	3	—
Sherwood Midstream	8	—	—
Other	5	7	1
Total	<u>\$92</u>	<u>\$ 86</u>	<u>\$ 58</u>

MPC provides executive management services and certain general and administrative services to the Partnership under the terms of an omnibus agreement. Expenses incurred under this agreement are shown in the table below by the income statement line where they were recorded. Charges for services included in *Purchases—related parties* primarily relate to services that support the Partnership’s operations and maintenance activities, as well as compensation expenses. Charges for services included in *General and administrative expenses* primarily relate to services that support the Partnership’s executive management, accounting and human resources activities. These charges were as follows:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Purchases—related parties	\$ 67	\$39	\$32
General and administrative expenses	37	45	53
Total	<u>\$104</u>	<u>\$84</u>	<u>\$85</u>

Also under terms of the omnibus agreement, some service costs related to engineering services are associated with assets under construction. These costs added to *Property, plant and equipment, net* were as follows:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
MPC	\$42	\$47	\$16

MPLX LP obtains employee services from MPC under employee services agreements. Expenses incurred under these agreements are shown in the table below by the income statement line where they were recorded. The costs of personnel directly involved in or supporting operations and maintenance activities are classified as *Purchases—related parties*. The costs of personnel involved in executive management, accounting and human resources activities are classified as *General and administrative expenses* in the Consolidated Statements of Income.

Employee services expenses from related parties were as follows:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Purchases—related parties	\$385	\$349	\$140
General and administrative expenses	101	100	22
Total	<u>\$486</u>	<u>\$449</u>	<u>\$162</u>

Purchases of products from MPC are classified as *Purchases—related parties*. Product purchases from related parties were as follows:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
MPC	\$3	\$—	\$—

Receivables from related parties, which for December 31, 2016, included reimbursements from the MarkWest Merger to be provided by MPC for the conversion of Class B units, were as follows:

<u>(In millions)</u>	<u>December 31,</u>	
	<u>2017</u>	<u>2016</u>
MPC	\$153	\$242
MarkWest Utica EMG	1	2
Ohio Gathering	2	2
Jefferson Dry Gas	2	—
Other	2	1
Total	<u>\$160</u>	<u>\$247</u>

Long-term receivables with related parties, which includes straight-line rental income, were as follows:

<u>(In millions)</u>	<u>December 31,</u>	
	<u>2017</u>	<u>2016</u>
MPC	\$20	\$11

Payables to related parties were as follows:

<u>(In millions)</u>	<u>December 31,</u>	
	<u>2017</u>	<u>2016</u>
MPC <sup>(1)</sup>	\$470	\$ 63
MarkWest Utica EMG	29	24
Ohio Gathering	8	—
Sherwood Midstream	8	—
Other	1	—
Total	<u>\$516</u>	<u>\$ 87</u>

<sup>(1)</sup> Balance includes approximately \$386 million related to the loan with MPC Investment discussed above.

*Other current assets* included \$8 million of related party prepaid insurance as of December 31, 2017.

From time to time, the Partnership may also sell to or purchase from related parties assets and inventory at the lesser of average unit cost or net realizable value. Sales to related parties during the years ended December 31, 2017 and 2016 were \$11 million and \$3 million, respectively. Purchases from related parties during the years ended December 31, 2017 and 2016 were approximately \$44 million and \$6 million, respectively.

During 2017 and 2016, MPC did not ship its minimum committed volumes on certain pipelines. Under the Partnership's pipeline transportation services agreements, if MPC fails to transport its minimum throughput volumes during any quarter, then MPC will pay the Partnership a deficiency payment equal to the volume of the deficiency multiplied by the tariff rate then in effect. The deficiency amounts are recorded as *Deferred revenue-related parties*. MPC may then apply the amount of any such deficiency payments as a credit for volumes transported on the applicable pipeline in excess of its minimum volume commitment during the following four or eight quarters under the terms of the applicable transportation services agreement. The Partnership recognizes revenues for the deficiency payments when credits are used for volumes transported in excess of minimum quarterly volume commitments, when it becomes impossible to physically transport volumes necessary to utilize the credits or upon the expiration of the credits. The use or expiration of the credits is a decrease in *Deferred revenue-related parties*. In addition, capital projects the Partnership is undertaking at the request of MPC are reimbursed in cash and recognized in income over the remaining term of the applicable agreements. The *Deferred revenue-related parties* balance associated with the minimum volume deficiencies and project reimbursements were as follows:

<u>(In millions)</u>	<u>December 31,</u>	
	<u>2017</u>	<u>2016</u>
Minimum volume deficiencies—MPC	\$53	\$48
Project reimbursements—MPC	<u>33</u>	<u>9</u>
Total	<u>\$86</u>	<u>\$57</u>

## 7. Net Income (Loss) Per Limited Partner Unit

Net income (loss) per unit applicable to common limited partner units and to subordinated limited partner units is computed by dividing the respective limited partners' interest in net income (loss) attributable to MPLX LP by the weighted average number of common units and subordinated units outstanding. Because the Partnership has more than one class of participating securities, it uses the two-class method when calculating the net income (loss) per unit applicable to limited partners. The classes of participating securities include common units, subordinated units, general partner units, preferred units, certain equity-based compensation awards and IDRs.

The HSM, HST, WHC and MPLXT acquisitions were transfers between entities under common control as discussed in Note 4. As entities under common control with MPC, prior periods were retrospectively adjusted to furnish comparative information. Accordingly, the prior period earnings have been allocated to the general partner and do not affect the net income (loss) per unit calculation. The earnings for the entities acquired under common control will be included in the net income (loss) per unit calculation prospectively as described above.

As discussed further in Note 8, the subordinated units, all of which were owned by MPC, were converted into common units during the third quarter of 2015. For purposes of calculating net income (loss) per unit, the subordinated units were treated as if they converted to common units on July 1, 2015.

In 2017, 2016 and 2015, the Partnership had dilutive potential common units consisting of certain equity-based compensation awards and Class B units. Potential common units omitted from the diluted earnings per unit calculation for the years ended December 31, 2017, 2016 and 2015 were less than one million.

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Net income attributable to MPLX LP	\$ 794	\$ 233	\$ 156
Less: Limited partners' distributions declared on Preferred units <sup>(1)</sup>	65	41	—
General partner's distributions declared (includes IDRs) <sup>(1)(2)</sup>	328	205	60
Limited partners' distributions declared on common units <sup>(1)</sup>	895	692	224
Limited partner's distributions declared on subordinated units <sup>(1)</sup>	<u>—</u>	<u>—</u>	<u>31</u>
Undistributed net loss attributable to MPLX LP	<u>\$(494)</u>	<u>\$(705)</u>	<u>\$(159)</u>

- (1) See Note 8 for distribution information.
- (2) Distributions declared on January 25, 2018 on general partner common units issued on February 1, 2018 in exchange for the economic general partner interest, including IDRs, are shown as general partner distributions declared.

	2017			
	General Partner	Limited Partners' Common Units	Redeemable Preferred Units	Total
<i>(In millions, except per unit data)</i>				
<b>Basic and diluted net income attributable to MPLX LP per unit:</b>				
Net income attributable to MPLX LP:				
Distributions declared (includes IDRs) <sup>(1)(2)</sup>	\$328	\$ 895	\$ 65	\$1,288
Undistributed net loss attributable to MPLX LP	(10)	(484)	—	(494)
Net income attributable to MPLX LP <sup>(1)</sup>	<u>\$318</u>	<u>\$ 411</u>	<u>\$ 65</u>	<u>\$ 794</u>
Weighted average units outstanding:				
Basic	8	385		393
Diluted	8	388		396
Net income attributable to MPLX LP per limited partner unit:				
Basic		\$ 1.07		
Diluted		\$ 1.06		

	2016			
	General Partner	Limited Partners' Common Units	Redeemable Preferred Units	Total
<i>(In millions, except per unit data)</i>				
<b>Basic and diluted net income attributable to MPLX LP per unit:</b>				
Net income attributable to MPLX LP:				
Distributions declared (including IDRs)	\$205	\$ 692	\$ 41	\$ 938
Undistributed net loss attributable to MPLX LP	(14)	(691)	—	(705)
Net income attributable to MPLX LP <sup>(1)</sup>	<u>\$191</u>	<u>\$ 1</u>	<u>\$ 41</u>	<u>\$ 233</u>
Weighted average units outstanding:				
Basic	7	331		338
Diluted	7	338		345
Net income attributable to MPLX LP per limited partner unit:				
Basic		\$ —		
Diluted		\$ —		



	2015			
<i>(In millions, except per unit data)</i>	General Partner	Limited Partners' Common Units	Limited Partner's Subordinated Units	Total
<b>Basic and diluted net income attributable to MPLX LP per unit:</b>				
Net income attributable to MPLX LP:				
Distribution declared	\$ 60	\$ 224	\$ 31	\$ 315
Undistributed net loss attributable to MPLX LP	<u>(3)</u>	<u>(127)</u>	<u>(29)</u>	<u>(159)</u>
Net income attributable to MPLX LP <sup>(1)</sup>	<u>\$ 57</u>	<u>\$ 97</u>	<u>\$ 2</u>	<u>\$ 156</u>
Weighted average units outstanding:				
Basic	2	79	18	99
Diluted	2	80	18	100
Net income attributable to MPLX LP per limited partner unit:				
Basic		\$ 1.23	\$ 0.11	
Diluted		\$ 1.22	\$ 0.11	

(1) Allocation of net income (loss) attributable to MPLX LP assumes all earnings for the period were distributed based on the current period distribution priorities.

## 8. Equity

**Units Outstanding**—The Partnership had 407,130,020 common units outstanding as of December 31, 2017. Of that number, 118,090,823 were owned by MPC, which also owned the two percent GP Interest represented by 8,308,773 general partner units.

**Subordinated Unit Conversion**—Following payment of the cash distribution for the second quarter of 2015, the requirements for the conversion of all subordinated units were satisfied under the Partnership Agreement. As a result, effective August 17, 2015, the 36,951,515 subordinated units owned by MPC were converted into common units on a one-for-one basis and thereafter participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of the cash distributions paid by the Partnership or the total units outstanding.

**Reorganization Transactions**—On September 1, 2016, the Partnership and various affiliates initiated a series of reorganization transactions in order to simplify the Partnership's ownership structure and its financial and tax reporting requirements (the "Class A Reorganization"). In connection with these transactions, all of the issued and outstanding MPLX LP Class A units, all of which were held by MarkWest Hydrocarbon, were either distributed to, or purchased by, MPC in exchange for \$84 million in cash, 21,401,137 MPLX LP common units and 436,758 MPLX LP general partner units. Following these initial transactions, the MPLX LP Class A units were exchanged on a one-for-one basis for newly issued common units representing limited partner interests in MPLX LP. MPC also contributed \$141 million to facilitate the repayment of intercompany debt between MarkWest Hydrocarbon and MarkWest. As a result of these transactions, the MPLX LP Class A units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership. Cash that is derived from or attributable to MarkWest Hydrocarbon's operations is now treated in the same manner as cash derived from or attributable to other operations of the Partnership and its subsidiaries.

**MarkWest Merger**—On December 4, 2015, the Partnership completed the MarkWest Merger. As defined in the merger agreement, each common unit of MarkWest issued and outstanding at the effective time of the MarkWest

Merger was converted into the right to receive 1.09 common units of MPLX LP. This resulted in the issuance of 216,350,465 common units. The Class A units of MarkWest outstanding immediately prior to the MarkWest Merger were converted into 28,554,313 Class A units of MPLX LP having substantially similar rights and obligations that the Class A units of MarkWest had immediately prior to the combination. Each outstanding Class B unit of MarkWest had, immediately prior to the merger, converted into the right to receive one Class B unit of MPLX LP having substantially similar rights, including conversion and registration rights, and obligations that the Class B units of MarkWest had immediately prior to the merger. This resulted in the issuance of 7,981,756 MPLX LP Class B units. Each Class B unit of MPLX LP was converted, in two equal installments, into 1.09 MPLX LP common units and the right to receive \$6.20 in cash, on July 1, 2016 and July 1, 2017. Upon the conversion of each tranche of the Class B units, the right of the unitholder, M&R MWE Liberty LLC and certain of its affiliates (“M&R”), to vote as a common unitholder of the Partnership was limited to a maximum of five percent of the Partnership’s outstanding common units. Additionally, M&R was given the right with respect to such converted units to participate in the Partnership’s underwritten offerings of our common units including continuous equity or similar programs in an amount up to 20 percent of the total number of common units offered by the Partnership. M&R may freely transfer such converted units, and M&R has the right to demand that MPLX LP conduct up to three underwritten offerings beginning in 2017, but restricted to no more than one offering in any twelve-month period. Following the July 1, 2017 conversion, all MPLX LP Class B units were eliminated, are no longer outstanding and no longer participate in distributions of cash from the Partnership.

**ATM Program**—On August 4, 2016, the Partnership entered into a second amended and restated distribution agreement (the “Distribution Agreement”), providing for the at-the-market issuances of common units, in amounts, at prices and on terms determined by market conditions and other factors at the time of the offerings (such continuous offering program, or at-the-market program is referred to as the “ATM Program”). During the years ended December 31, 2017, 2016, and 2015, the Partnership issued an aggregate of 13,846,998, 26,347,887, and 25,166 common units, respectively, under our ATM Program, generating net proceeds of approximately \$473 million, \$776 million, and \$1 million, respectively. The Partnership used the net proceeds from sales under the ATM Program for general partnership purposes, including repayment or refinancing of debt, and funding for acquisitions, working capital requirements and capital expenditures.

The table below summarizes the changes in the number of units outstanding for the years ended December 31, 2015, 2016, and 2017:

<i>(In units)</i>	Common	Class B	Subordinated	General Partner <sup>(1)</sup>	Total
<b>Balance at December 31, 2014</b>	43,341,098	—	36,951,515	1,638,625	81,931,238
Unit-based compensation awards	18,932	—	—	386	19,318
Issuance of units under the ATM Program	25,166	—	—	514	25,680
Subordinated unit conversion	36,951,515	—	(36,951,515)	—	—
MarkWest Merger	216,350,465	7,981,756	—	5,160,950	229,493,171
<b>Balance at December 31, 2015</b>	296,687,176	7,981,756	—	6,800,475	311,469,407
Unit-based compensation awards	120,989	—	—	2,470	123,459
Issuance of units under the ATM Program	26,347,887	—	—	537,710	26,885,597
Contribution of HSM (See Note 4)	22,534,002	—	—	459,878	22,993,880
Class B conversion	4,350,057	(3,990,878)	—	7,330	366,509
Class A Reorganization	7,153,177	—	—	(436,758)	6,716,419
<b>Balance at December 31, 2016</b>	357,193,288	3,990,878	—	7,371,105	368,555,271
Unit-based compensation awards	268,167	—	—	5,472	273,639
Issuance of units under the ATM Program	13,846,998	—	—	282,591	14,129,589
Contribution of HST/WHC/MPLXT (See Note 4)	12,960,376	—	—	264,497	13,224,873
Contribution of the Joint Interest Acquisition (See Note 4)	18,511,134	—	—	377,778	18,888,912
Class B conversion	4,350,057	(3,990,878)	—	7,330	366,509
<b>Balance at December 31, 2017</b>	407,130,020	—	—	8,308,773	415,438,793

(1) Changes to the number of general partner units outstanding, other than changes due to contributions made to MPC for the acquisitions of HSM, HST, WHC, MPLXT and the Joint Interest Acquisition, are the result of cash contributions made by the general partner in order to maintain its two percent GP Interest.

**Issuance of Additional Securities**—The Partnership Agreement authorizes the Partnership to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by the general partner without the approval of the unitholders.

**Net Income Allocation**—In preparing the Consolidated Statements of Equity, net income attributable to MPLX LP is allocated to Preferred unitholders based on a fixed distribution schedule, as discussed in Note 9, and subsequently allocated to the general partner and limited partner unitholders. However, when distributions related to the IDRs are made, earnings equal to the amount of those distributions are first allocated to the general partner before the remaining earnings are allocated to the unitholders, based on their respective ownership percentages. The following table presents the allocation of the general partner’s GP Interest in net income attributable to MPLX LP:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Net income attributable to MPLX LP	\$794	\$233	\$156
Less: Preferred unit distributions	65	41	—
General partner’s IDRs and other	310	191	55
Net income attributable to MPLX LP available to general and limited partners	<u>\$419</u>	<u>\$ 1</u>	<u>\$101</u>
General partner’s two percent GP Interest in net income attributable to MPLX LP	\$ 8	\$—	\$ 2
General partner’s IDRs and other	310	191	55
General partner’s GP Interest in net income attributable to MPLX LP	<u>\$318</u>	<u>\$191</u>	<u>\$ 57</u>

**Cash Distributions**—The Partnership Agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders, Preferred unitholders and general partner will receive. In accordance with the Partnership Agreement, on January 26, 2018, the Partnership declared a quarterly cash distribution, based on the results of the fourth quarter of 2017, totaling \$346 million, or \$0.6075 per unit. This distribution was paid on February 14, 2018 to unitholders of record on February 5, 2018. See the table below for the IDR impact for 2017.

The allocation of total quarterly cash distributions to general, limited, and Preferred unitholders is as follows for the years ended December 31, 2017, 2016 and 2015. The Partnership’s distributions are declared subsequent to quarter end; therefore, the following table represents total cash distributions applicable to the period in which the distributions were earned.

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>General partner’s distributions:</b>			
General partner’s distributions on general partner units	\$ 25	\$ 18	\$ 6
General partner’s distributions on IDRs <sup>(1)</sup>	303	187	54
Total distribution on general partner units and IDRs	<u>328</u>	<u>205</u>	<u>60</u>
<b>Limited partners’ distributions:</b>			
Common unitholders, includes common units of general partner	895	692	224
Subordinated unitholders	—	—	31
Total limited partners’ distributions	<u>895</u>	<u>692</u>	<u>255</u>
<b>Preferred unit distributions</b>	65	41	—
Total cash distributions declared	<u>\$1,288</u>	<u>\$938</u>	<u>\$315</u>

<sup>(1)</sup> Includes distributions of fourth quarter 2017 income declared on general partner common units issued February 1, 2018 in exchange for the economic general partner interest.

## 9. Redeemable Preferred Units

**Private Placement of Preferred Units**—On May 13, 2016, MPLX LP completed the private placement of approximately 30.8 million 6.5 percent Series A Convertible Preferred units (the “Preferred units”) for a cash purchase price of \$32.50 per unit. The aggregate net proceeds of approximately \$984 million from the sale of the Preferred units were used for capital expenditures, repayment of debt and general partnership purposes.

The Preferred units rank senior to all common units with respect to distributions and rights upon liquidation. The holders of the Preferred units are entitled to receive cumulative quarterly distributions equal to \$0.528125 per unit, commencing for the quarter ended June 30, 2016, with a prorated amount from the date of issuance. Following the second anniversary of the issuance of the Preferred units, the holders of the Preferred units will be entitled to receive as a quarterly distribution the greater of \$0.528125 per unit or the amount of per unit distributions paid to holders of MPLX LP common units. Since the Preferred unit distribution was declared subsequent to the end of the second quarter of 2016, the distribution was not accrued to the Preferred unitholders' capital account. For the quarter ended June 30, 2016, the Preferred units received an earned aggregate cash distribution of \$9 million, based on the quarterly per unit distribution prorated for the 49-day period the Preferred units were outstanding during the second quarter of 2016.

The changes in the redeemable preferred balance for 2017 and 2016 are summarized below:

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>
Balance at beginning of period	\$1,000	\$ —
Issuance of Preferred units	—	984
Net income allocated	65	41
Distributions received by Preferred unitholders	<u>(65)</u>	<u>(25)</u>
Balance at end of period	<u>\$1,000</u>	<u>\$1,000</u>

The holders may convert their Preferred units into common units at any time after the third anniversary of the issuance date or prior to liquidation, dissolution or winding up of the Partnership, in full or in part, subject to minimum conversion amounts and conditions. After the fourth anniversary of the issuance date, the Partnership may convert the Preferred units into common units at any time, in whole or in part, subject to certain minimum conversion amounts and conditions, if the closing price of MPLX LP common units is greater than \$48.75 for the 20 day trading period immediately preceding the conversion notice date. The conversion rate for the Preferred units shall be the quotient of (a) the sum of (i) \$32.50, plus (ii) any unpaid cash distributions on the applicable Preferred unit, divided by (b) \$32.50. The holders of the Preferred units are entitled to vote on an as-converted basis with the common unitholders and (as proportionately adjusted for unit splits, unit distributions and similar transactions) will have certain other class voting rights with respect to any amendment to the Partnership Agreement that would adversely affect any rights, preferences or privileges of the Preferred units. In addition, upon certain events involving a change of control the holders of Preferred units may elect, among other potential elections, to convert their Preferred units to common units at the then change of control conversion rate.

The Preferred units are considered redeemable securities under GAAP due to the existence of redemption provisions upon a deemed liquidation event which is outside the Partnership's control. Therefore they are presented as temporary equity in the mezzanine section of the Consolidated Balance Sheets. The Preferred units have been recorded at their issuance date fair value, net of issuance costs. Income allocations increase the carrying value, and declared distributions decreased the carrying value of the Preferred units. As the Preferred units are not currently redeemable and not probable of becoming redeemable, adjustment to the initial carrying amount is not necessary and would only be required if it becomes probable that the Preferred units would become redeemable.

## 10. Segment Information

The Partnership's chief operating decision maker is the chief executive officer ("CEO") of its general partner. The CEO reviews the Partnership's discrete financial information, makes operating decisions, assesses financial performance and allocates resources on a type of service basis. The Partnership has two reportable segments: L&S and G&P. Each of these segments is organized and managed based upon the nature of the products and services it offers.

- L&S—transports, stores and distributes crude oil and refined petroleum products. Segment information for prior periods includes retrospective adjustments in connection with the acquisitions of HSM, HST,

WHC and MPLXT. Segment information is not included for periods prior to the Joint-Interest Acquisition and the Ozark pipeline acquisitions. See Note 4 for more detail of these acquisitions.

- G&P—gathers, processes and transports natural gas; gathers, transports, fractionates, stores and markets NGLs. This segment is the result of the MarkWest Merger on December 4, 2015 discussed in more detail in Note 4. Segment information for periods prior to the MarkWest Merger does not include amounts for these operations.

The Partnership has investments in entities that are accounted for using the equity method of accounting (see Note 5). However, the CEO only views the Partnership-operated equity method investments' financial information as if those investments were consolidated, in contrast to the non-operated equity method investments.

Segment operating income represents income from operations attributable to the reportable segments. Corporate general and administrative expenses, unrealized derivative gains (losses), goodwill impairment, certain management fees and depreciation and amortization are not allocated to the reportable segments. Management does not consider these items allocable to or controllable by any individual segment and, therefore, excludes these items when evaluating segment performance. Segment results are also adjusted to exclude the portion of income from operations attributable to the noncontrolling interests related to partially-owned entities that are either consolidated or accounted for as equity method investments. Segment operating income attributable to MPLX LP excludes the operating income related to Predecessors of the HSM, HST, WHC and MPLXT businesses prior to the dates they were acquired by MPLX LP.

The tables below present information about income from operations and capital expenditures for the reported segments:

<i>(In millions)</i>	2017		
	L&S	G&P	Total
<b>Revenues and other income:</b>			
Segment revenues	\$1,480	\$2,609	\$4,089
Segment other income	47	1	48
Total segment revenues and other income	1,527	2,610	4,137
<b>Costs and expenses:</b>			
Segment cost of revenues	692	1,105	1,797
Segment operating income before portion attributable to noncontrolling interests and Predecessor	835	1,505	2,340
Segment portion attributable to noncontrolling interests and Predecessor	53	170	223
<b>Segment operating income attributable to MPLX LP</b>	<b>\$ 782</b>	<b>\$1,335</b>	<b>\$2,117</b>
<i>(In millions)</i>	2016		
	L&S	G&P	Total
<b>Revenues and other income:</b>			
Segment revenues	\$1,241	\$2,185	\$3,426
Segment other income	53	1	54
Total segment revenues and other income	1,294	2,186	3,480
<b>Costs and expenses:</b>			
Segment cost of revenues	552	907	1,459
Segment operating income before portion attributable to noncontrolling interests and Predecessor	742	1,279	2,021
Segment portion attributable to noncontrolling interests and Predecessor	289	147	436
<b>Segment operating income attributable to MPLX LP</b>	<b>\$ 453</b>	<b>\$1,132</b>	<b>\$1,585</b>

<i>(In millions)</i>	2015		
	L&S	G&P	Total
<b>Revenues and other income:</b>			
Segment revenues	\$ 913	\$ 150	\$1,063
Segment other income	62	—	62
Total segment revenues and other income	975	150	1,125
<b>Costs and expenses:</b>			
Segment cost of revenues	416	62	478
Segment operating income before portion attributable to noncontrolling interests and Predecessor	559	88	647
Segment portion attributable to noncontrolling interests and Predecessor	237	12	249
<b>Segment operating income attributable to MPLX LP</b>	<b>\$ 322</b>	<b>\$ 76</b>	<b>\$ 398</b>

<i>(In millions)</i>	2017	2016	2015
<b>Reconciliation to Income from operations:</b>			
L&S segment operating income attributable to MPLX LP	\$ 782	\$ 453	\$ 322
G&P segment operating income attributable to MPLX LP	1,335	1,132	76
Segment operating income attributable to MPLX LP	2,117	1,585	398
Segment portion attributable to unconsolidated affiliates	(178)	(173)	(8)
Segment portion attributable to Predecessor	53	289	236
Income (loss) from equity method investments <sup>(1)</sup>	78	(74)	3
Other income—related parties	51	40	2
Unrealized derivative (losses) gains <sup>(2)</sup>	(6)	(36)	4
Depreciation and amortization	(683)	(591)	(129)
Impairment expense	—	(130)	—
General and administrative expenses	(241)	(227)	(125)
<b>Income from operations</b>	<b>\$1,191</b>	<b>\$ 683</b>	<b>\$ 381</b>

<i>(In millions)</i>	2017	2016	2015
<b>Reconciliation to Total revenues and other income:</b>			
Total segment revenues and other income	\$4,137	\$3,480	\$1,125
Revenue adjustment from unconsolidated affiliates	(403)	(402)	(28)
Income (loss) from equity method investments <sup>(1)</sup>	78	(74)	3
Other income—related parties	51	40	2
Unrealized derivative gains (losses) related to product sales <sup>(2)</sup>	4	(15)	(1)
<b>Total revenues and other income</b>	<b>\$3,867</b>	<b>\$3,029</b>	<b>\$1,101</b>

<sup>(1)</sup> Includes an impairment expense of \$89 million related to one of the Partnership's equity method investments for the year ended December 31, 2016.

<sup>(2)</sup> The Partnership makes a distinction between realized or unrealized gains and losses on derivatives. During the period when a derivative contract is outstanding, changes in the fair value of the derivative are recorded as an unrealized gain or loss. When a derivative contract matures or is settled, the previously recorded unrealized gain or loss is reversed and the realized gain or loss of the contract is recorded.

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
<b>Reconciliation to Net income attributable to noncontrolling interests and Predecessor:</b>			
Segment portion attributable to noncontrolling interests and Predecessor	\$ 223	\$ 436	\$ 249
Portion of noncontrolling interests and Predecessor related to items below segment income from operations	(106)	(203)	(67)
Portion of operating income attributable to noncontrolling interests of unconsolidated affiliates	<u>(75)</u>	<u>(32)</u>	<u>(5)</u>
<b>Net income attributable to noncontrolling interests and Predecessor</b>	<b><u>\$ 42</u></b>	<b><u>\$ 201</u></b>	<b><u>\$ 177</u></b>

The following table reconciles segment capital expenditures to total capital expenditures:

<i>(In millions)</i>	<u>2017</u>	<u>2016</u>	<u>2015</u>
L&S segment capital expenditures	\$ 498	\$ 550	\$258
G&P segment capital expenditures	<u>1,297</u>	<u>894</u>	<u>100</u>
Total segment capital expenditures	1,795	1,444	358
Less: Capital expenditures for Partnership-operated, non-wholly-owned subsidiaries in G&P segment	<u>384</u>	<u>131</u>	<u>24</u>
Total capital expenditures	<b><u>\$1,411</u></b>	<b><u>\$1,313</u></b>	<b><u>\$334</u></b>

Total assets by reportable segment were:

<i>(In millions)</i>	December 31,	
	<u>2017</u>	<u>2016</u>
Cash and cash equivalents	\$ 5	\$ 234
L&S	4,611	2,978
G&P	<u>14,884</u>	<u>14,297</u>
Total assets	<b><u>\$19,500</u></b>	<b><u>\$17,509</u></b>

Equity method investments included in L&S assets were \$1,148 million and \$4 million at December 31, 2017 and 2016, respectively. Equity method investments included in G&P assets were \$2,862 million and \$2,467 million at December 31, 2017 and 2016, respectively.

## 11. Major Customers and Concentration of Credit Risk

MPC accounted for 37 percent of the Partnership's operating revenues for 2017, and 41 percent and 82 percent of the Partnership's total revenues and other income for 2016 and 2015, respectively. The percent calculations exclude revenues attributable to volumes shipped by MPC under joint tariffs with third parties, which are treated as third-party revenue for accounting purposes.

The Partnership has a concentration of trade receivables due from customers in the same industry, MPC, integrated oil companies, independent refining companies and other pipeline companies. These concentrations of customers may impact the Partnership's overall exposure to credit risk as they may be similarly affected by changes in economic, regulatory and other factors. The Partnership manages its exposure to credit risk through credit analysis, credit limit approvals and monitoring procedures, and for certain transactions, it may request letters of credit, prepayments or guarantees.

## 12. Income Tax

The Partnership is not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on the Partnership's net income generally are borne by its partners through the



allocation of taxable income. On December 22, 2017, the Tax Cuts and Jobs Act was signed into law. The new law included several key changes to tax law for United States tax payers, as the Partnership is not a taxable entity the new legislation has no impact for federal tax purposes. The Partnership's income tax provision (benefit) primarily results from partnership activity in the states of Texas, Ohio and Tennessee.

As a result of the Class A Reorganization discussed in Note 8, MarkWest Hydrocarbon (MarkWest Hydrocarbon, Inc. prior to the Class A Reorganization) is no longer a tax paying entity for federal income tax purposes or for the majority of states that impose an income tax effective September 1, 2016. The Partnership recorded a residual tax provision during the year ending December 31, 2017 related to MarkWest Hydrocarbon's 2016 income taxes. In connection with the Class A Reorganization, MPC assumed \$377 million of MPLX LP's deferred tax liabilities.

The Partnership and MarkWest Hydrocarbon recorded income tax expense (benefit) of \$1 million, \$(12) million and \$1 million for the years ended December 31, 2017, 2016 and 2015, respectively. The effective tax rate was less than one percent for 2017, five percent for 2016 and less than one percent for 2015.

The components of the provision for income tax expense (benefit) are as follows:

<i>(In millions)</i>	December 31,		
	2017	2016	2015
Current income tax expense:			
Federal	\$—	\$ 4	\$—
State	<u>2</u>	<u>1</u>	<u>—</u>
Total current	<u>2</u>	<u>5</u>	<u>—</u>
Deferred income tax expense (benefit):			
Federal	—	(16)	3
State	<u>(1)</u>	<u>(1)</u>	<u>(2)</u>
Total deferred	<u>(1)</u>	<u>(17)</u>	<u>1</u>
Provision (benefit) for income tax	<u>\$ 1</u>	<u>\$(12)</u>	<u>\$ 1</u>

A reconciliation of the (benefit) provision for income tax and the amount computed by applying the federal statutory rate of 35 percent to the income before income taxes for each of the years ended December 31, 2016 and 2015 is as follows:

<i>(In millions)</i>	December 31, 2016			
	MarkWest Hydrocarbon <sup>(1)</sup>	Partnership	Eliminations	Consolidated
(Loss) income before (benefit) provision for income tax	\$(41)	\$461	\$ 2	\$422
Federal statutory rate	<u>35%</u>	<u>— %</u>	<u>— %</u>	<u>—</u>
Federal income tax at statutory rate	(14)	—	—	(14)
State income taxes net of federal benefit	(2)	1	—	(1)
Provision on income from MPLX LP Class A units	3	—	—	3
Change in state statutory rate	(1)	—	—	(1)
Other	<u>1</u>	<u>—</u>	<u>—</u>	<u>1</u>
(Benefit) provision for income tax	<u>\$(13)</u>	<u>\$ 1</u>	<u>\$—</u>	<u>\$(12)</u>

<i>(In millions)</i>	December 31, 2015			
	MarkWest Hydrocarbon <sup>(1)</sup>	Partnership	Eliminations	Consolidated
Income before provision (benefit) for income tax	\$ 9	\$324	\$ 1	\$334
Federal statutory rate	35%	— %	— %	—
Federal income tax at statutory rate	3	—	—	3
State income taxes net of federal benefit	—	(2)	—	(2)
Provision on income from MPLX LP Class A units	1	—	—	1
Other	(1)	—	—	(1)
Provision (benefit) for income tax	<u>\$ 3</u>	<u>\$ (2)</u>	<u>\$—</u>	<u>\$ 1</u>

<sup>(1)</sup> MarkWest Hydrocarbon paid tax on its share of the Partnership's income or loss as a result of its ownership of MPLX LP Class A units through September 1, 2016.

In taxable jurisdictions, the Partnership recorded deferred income taxes on all temporary differences between the book and tax basis of assets and liabilities. The Partnership has a net deferred tax liability of \$5 million and \$6 million for the years ended December 31, 2017 and 2016, respectively. The net deferred tax liability is principally derived from the difference in the book and tax basis of property, plant and equipment.

Significant judgment is required in evaluating tax positions and determining the Partnership and MarkWest Hydrocarbon's provision for income taxes. During the ordinary course of business, there may be transactions and calculations for which the ultimate tax determination is uncertain. However, the Partnership and MarkWest Hydrocarbon did not have any material uncertain tax positions for the years ended December 31, 2017, 2016 or 2015.

Any interest and penalties related to income taxes were recorded as a part of the provision for income taxes. Such interest and penalties were a net benefit of less than \$1 million in 2017 and 2016, and a net expense of less than \$1 million for 2015. As of December 31, 2017 and 2016, no interest and penalties were accrued related to income taxes. In addition, the Partnership and MarkWest Hydrocarbon's former corporate entity have federal tax years 2013 through 2016 and state tax years 2012 through 2016 open to examination.

### 13. Inventories

Inventories consist of the following:

<i>(In millions)</i>	December 31,	
	2017	2016
NGLs	\$ 4	\$ 2
Line fill	8	9
Spare parts, materials and supplies	53	44
Total inventories	<u>\$ 65</u>	<u>\$ 55</u>

## 14. Property, Plant and Equipment

Property, plant and equipment with associated accumulated depreciation is shown below:

<i>(In millions)</i>	Estimated Useful Lives	December 31,	
		2017	2016
Natural gas gathering and NGL transportation pipelines and facilities	5 - 30 years	\$ 5,178	\$ 4,748
Processing, fractionation and storage facilities <sup>(1)</sup>	10 - 40 years	3,893	3,547
Pipelines and related assets	15 - 49 years	2,253	1,799
Barges and towing vessels	20 years	490	479
Terminals and related assets <sup>(1)</sup>	4 - 30 years	821	759
Land, building, office equipment and other	3 - 35 years	770	757
Construction-in-progress		<u>1,057</u>	<u>1,013</u>
Total		14,462	13,102
Less accumulated depreciation		<u>2,275</u>	<u>1,694</u>
Property, plant and equipment, net		<u>\$12,187</u>	<u>\$11,408</u>

<sup>(1)</sup> Certain prior period amounts have been updated to conform to current period presentation.

Property, plant and equipment includes gross assets acquired under capital leases of approximately \$25 million at December 31, 2017 and 2016, respectively, with related amounts in accumulated depreciation of approximately \$9 million and \$8 million at December 31, 2017 and 2016, respectively.

## 15. Fair Value Measurements

### *Fair Values—Recurring*

The following table presents the financial instruments carried at fair value on a recurring basis as of December 31, 2017 and 2016 by fair value hierarchy level. The Partnership has elected to offset the fair value amounts recognized for multiple derivative contracts executed with the same counterparty.

<i>(In millions)</i>	December 31, 2017		December 31, 2016	
	Assets	Liabilities	Assets	Liabilities
<i>Significant unobservable inputs (Level 3)</i>				
Commodity contracts	\$—	\$ (2)	\$—	\$ (6)
Embedded derivatives in commodity contracts	<u>—</u>	<u>(64)</u>	<u>—</u>	<u>(54)</u>
Total carrying value in Consolidated Balance Sheets	<u>\$—</u>	<u>\$(66)</u>	<u>\$—</u>	<u>\$(60)</u>

Level 2 instruments include all crude oil and natural gas swap contracts. The valuations are based on the appropriate commodity prices and contain no significant unobservable inputs. LIBO rates are an observable input for the measurement of all derivative contracts. The measurements for commodity contracts contain observable inputs in the form of forward prices based on WTI crude oil prices; and Columbia Appalachia, Henry Hub, PEPL and Houston Ship Channel natural gas prices.

Level 3 instruments include all NGL transactions and embedded derivatives in commodity contracts. The embedded derivative liability relates to a natural gas purchase agreement embedded in a keep-whole processing agreement. The fair value calculation for Level 3 instruments at December 31, 2017 used significant unobservable inputs including: (1) NGL prices interpolated and extrapolated due to inactive markets ranging from \$0.24 to \$1.45 and (2) the probability of renewal of 60 percent for the first five year term and 80 percent for the second five year term of the gas purchase agreement and related keep-whole processing agreement. For these contracts, increases in forward NGL prices result in a decrease in the fair value of the derivative assets and an

increase in the fair value of derivative liabilities. The forward prices for NGL products generally increase or decrease in positive correlation with one another. Increases or decreases in forward NGL prices result in an increase or decrease in the fair value of the embedded derivative. An increase in the probability of renewal would result in an increase in the fair value of the related embedded derivative liability.

### ***Fair Values—Nonrecurring***

See Note 5 for detail of the Ohio Condensate equity method impairment charge, which included a Level 3 valuation adjustment for the year ended December 31, 2016.

See Note 18 for a rollforward of goodwill, which included a Level 3 valuation adjustment for the year ended December 31, 2016.

### ***Changes in Level 3 Fair Value Measurements***

The following table is a reconciliation of the net beginning and ending balances recorded for net assets and liabilities classified as Level 3 in the fair value hierarchy.

<i>(In millions)</i>	2017		2016	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	\$ (6)	\$ (54)	\$ 7	\$ (32)
Total loss (realized and unrealized) included in earnings <sup>(1)</sup>	(5)	(19)	(13)	(29)
Settlements	9	9	—	7
Fair value at end of period	<u>\$ (2)</u>	<u>\$ (64)</u>	<u>\$ (6)</u>	<u>\$ (54)</u>
The amount of total losses for the period included in earnings attributable to the change in unrealized gains or losses relating to liabilities still held at end of period	\$ (2)	\$ (6)	\$ (6)	\$ (26)

- <sup>(1)</sup> Gains and losses on commodity derivatives classified as Level 3 are recorded in *Product sales* in the accompanying Consolidated Statements of Income. Gains and losses on derivatives embedded in commodity contracts are recorded in *Purchased product costs* and *Cost of revenues*.

### ***Fair Values—Reported***

The Partnership's primary financial instruments are cash and cash equivalents, receivables, receivables from related parties, accounts payable, payables to related parties and long-term debt. The Partnership's fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) MPC's investment-grade credit rating and (3) the historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk. The Partnership believes the carrying values of its current assets and liabilities approximate fair value. The recorded value of the amounts outstanding under the bank revolving credit facility, if any, approximates fair value due to the variable interest rate that approximates current market rates. Derivative instruments are recorded at fair value, based on available market information (see Note 16).

The fair value of the Partnership's long-term debt is estimated based on recent market non-binding indicative quotes. The fair value of the steam methane reformer ("SMR") liability is estimated using a discounted cash flow approach based on the contractual cash flows and the Partnership's unsecured borrowing rate. The long-term debt

and SMR liability fair values are considered Level 3 measurements. The following table summarizes the fair value and carrying value of the Partnership's long-term debt, excluding capital leases, and SMR liability.

<i>(In millions)</i>	December 31,			
	2017		2016	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Long-term debt	\$7,718	\$6,966	\$4,953	\$4,422
SMR liability	104	91	108	96

## 16. Derivative Financial Instruments

As of December 31, 2017, the Partnership had the following outstanding commodity contracts that were executed to manage the cash flow risk associated with future sales of NGLs and purchases of natural gas:

<u>Derivative contracts not designated as hedging instruments</u>	<u>Financial Position</u>	<u>Notional Quantity (net)</u>
Natural Gas (MMBtu)	Long	928,003
NGLs (gal)	Short	9,586,503

*Embedded Derivative*—The Partnership has a natural gas purchase commitment embedded in a keep-whole processing agreement with a producer customer in the Southern Appalachian region expiring in December 2022. The customer has the unilateral option to extend the agreement for two consecutive five year terms through December 2032. For accounting purposes, these natural gas purchase commitment and term extending options have been aggregated into a single compound embedded derivative. The probability of the customer exercising its options is determined based on assumptions about the customer's potential business strategy decision points that may exist at the time they would elect whether to renew the contract. The changes in fair value of this compound embedded derivative are based on the difference between the contractual and index pricing, the probability of the producer customer exercising its option to extend and the estimated favorability of these contracts compared to current market conditions. The changes in fair value are recorded in earnings through *Purchased product costs* in the Consolidated Statements of Income. As of December 31, 2017 and 2016, the estimated fair value of this contract was a liability of \$64 million and \$54 million, respectively.

Certain derivative positions are subject to master netting agreements; therefore the Partnership has elected to offset derivative assets and liabilities that are legally permissible to be offset. As of December 31, 2017 and 2016, there were no derivative assets or liabilities that were offset in the Consolidated Balance Sheets. The impact of the Partnership's derivative instruments on its Consolidated Balance Sheets is summarized below:

<i>(In millions)</i>	December 31, 2017		December 31, 2016	
	<u>Asset</u>	<u>Liability</u>	<u>Asset</u>	<u>Liability</u>
<u>Derivative contracts not designated as hedging instruments and their balance sheet location</u>				
Commodity contracts <sup>(1)</sup>				
Other current assets / other current liabilities	\$—	\$(14)	\$—	\$(13)
Other noncurrent assets / deferred credits and other liabilities	—	(52)	—	(47)
Total	<u>\$—</u>	<u>\$(66)</u>	<u>\$—</u>	<u>\$(60)</u>

<sup>(1)</sup> Includes embedded derivatives in commodity contracts as discussed above.

For further information regarding the fair value measurement of derivative instruments, including the effect of master netting arrangements or collateral, see Note 15. See Note 2 for a discussion of derivatives the Partnership uses and the reasons for them. The Partnership does not designate any of its commodity derivative positions as hedges for accounting purposes.

The impact of the Partnership's derivative contracts not designated as hedging instruments and the location of (loss) or gain recognized in the Consolidated Statements of Income is summarized below:

<i>(In millions)</i>	December 31,	
	2017	2016
<b>Product sales</b>		
Realized (loss) gain	\$ (9)	\$ 2
Unrealized gain (loss)	4	(15)
Total derivative loss related to product sales	<u>(5)</u>	<u>(13)</u>
<b>Purchased product costs</b>		
Realized loss	(9)	(5)
Unrealized loss	<u>(10)</u>	<u>(22)</u>
Total derivative loss related to purchased product costs	<u>(19)</u>	<u>(27)</u>
<b>Cost of revenues</b>		
Realized loss	—	(3)
Unrealized gain	<u>—</u>	<u>1</u>
Total derivative loss related to cost of revenues	<u>—</u>	<u>(2)</u>
Total derivative losses	<u>\$ (24)</u>	<u>\$ (42)</u>

## 17. Debt

The Partnership's outstanding borrowings at December 31, 2017 and 2016 consisted of the following:

<i>(In millions)</i>	December 31,	
	2017	2016
<b>MPLX LP:</b>		
Bank revolving credit facility due 2022	\$ 505	\$ —
Term loan facility due 2019	—	250
5.500% senior notes due February 2023	710	710
4.500% senior notes due July 2023	989	989
4.875% senior notes due December 2024	1,149	1,149
4.000% senior notes due February 2025	500	500
4.875% senior notes due June 2025	1,189	1,189
4.125% senior notes due March 2027	1,250	—
5.200% senior notes due March 2047	1,000	—
<b>Consolidated subsidiaries:</b>		
MarkWest—4.500%—5.500% senior notes, due 2023-2025	63	63
MPL—capital lease obligations due 2020	<u>7</u>	<u>8</u>
Total	7,362	4,858
Unamortized debt issuance costs	(27)	(7)
Unamortized discount <sup>(1)</sup>	(389)	(428)
Amounts due within one year	<u>(1)</u>	<u>(1)</u>
Total long-term debt due after one year	<u>\$6,945</u>	<u>\$4,422</u>

<sup>(1)</sup> Includes \$374 million and \$420 million discount as of December 31, 2017 and 2016, respectively, related to the difference between the fair value and the principal amount of the assumed MarkWest debt.

The following table shows five years of scheduled debt payments.

<i>(In millions)</i>	
2018	\$ 1
2019	1
2020	5
2021	—
2022	505

### ***Credit Agreements***

On November 20, 2014, MPLX LP entered into a credit agreement with a syndicate of lenders which provided for a five-year, \$1 billion bank revolving credit facility and a \$250 million term loan facility. The term loan facility was drawn in full on November 20, 2014. In connection with the closing of the MarkWest Merger, the aggregate capacity of the credit facility was extended to \$2 billion, and the maturity date was extended to December 4, 2020. On July 21, 2017, the Partnership replaced the previously outstanding revolving credit facility with a \$2.25 billion five-year bank revolving credit facility that expires in July 2022 (the “MPLX Credit Agreement”). The financial covenants and the interest rate terms contained in the new credit agreement are substantially the same as those contained in the previous bank revolving credit facility. On July 19, 2017, the Partnership prepaid the entire outstanding principal of this loan facility with cash on hand. The borrowings under the term loan facility bore interest between January 1, 2017 and July 19, 2017 at an average interest rate of 2.407 percent.

The MPLX Credit Agreement includes letter of credit issuing capacity of up to \$222 million and swingline capacity of up to \$100 million. The borrowing capacity under the MPLX Credit Agreement may be increased by up to an additional \$500 million, subject to certain conditions, including the consent of lenders whose commitments would increase. In addition, the maturity date may be extended, for up to two additional one-year periods, subject to the approval of lenders holding the majority of the commitments then outstanding, provided that the commitments of any non-consenting lenders will terminate on the then-effective maturity date. Borrowings under the MPLX Credit Agreement bear interest at either the Adjusted LIBOR or the Alternate Base Rate (as defined in the MPLX Credit Agreement), at our election, plus a specified margin. The Partnership is charged various fees and expenses in connection with the agreement, including administrative agent fees, commitment fees on the unused portion of the facility and fees with respect to issued and outstanding letters of credit. The applicable margins to the benchmark interest rates and certain fees fluctuate based on the credit ratings in effect from time to time on the Partnership’s long-term debt.

The MPLX Credit Agreement contains certain representations and warranties, affirmative and restrictive covenants and events of default that the Partnership considers to be usual and customary for an agreement of this type, including a financial covenant that requires the Partnership to maintain a ratio of Consolidated Total Debt as of the end of each fiscal quarter to Consolidated EBITDA (both as defined in the MPLX Credit Agreement) for the prior four fiscal quarters of no greater than 5.0 to 1.0 (or 5.5 to 1.0 for up to two fiscal quarters following certain acquisitions). Consolidated EBITDA is subject to adjustments for certain acquisitions and dispositions completed and capital projects undertaken during the relevant period. Other covenants restrict the Partnership and/or certain of its subsidiaries from incurring debt, creating liens on our assets and entering into transactions with affiliates. As of December 31, 2017, the Partnership was in compliance with the covenants contained in the MPLX Credit Agreement.

During 2017, the Partnership had no borrowings under the previous bank revolving credit facility. During the year ended December 31, 2017, the Partnership borrowed \$670 million under the MPLX Credit Agreement, at a weighted average interest rate of 2.748 percent and repaid \$165 million of these borrowings. At December 31, 2017, the Partnership had \$505 million outstanding borrowings and \$3 million letters of credit outstanding under the new facility, resulting in total availability of \$1.7 billion, or 77.4 percent of the borrowing capacity.

During 2016, the Partnership borrowed \$434 million under the previous bank revolving credit facility, at an average interest rate of 1.899 percent, per annum, and repaid \$1.3 billion of these borrowings. At December 31, 2016, the Partnership had no borrowings and \$3 million letters of credit outstanding under this facility, resulting in total unused loan availability of \$2 billion, or 99.9 percent of the borrowing capacity.

### **Senior Notes**

Interest on each series of MPLX LP and MarkWest senior notes is payable semi-annually in arrears, according to the table below.

<u>Senior Notes</u>	<u>Interest payable semi-annually in arrears</u>
5.500% senior notes due 2023	February 15 <sup>th</sup> and August 15 <sup>th</sup>
4.500% senior notes due 2023	January 15 <sup>th</sup> and July 15 <sup>th</sup>
4.875% senior notes due 2024	June 1 <sup>st</sup> and December 1 <sup>st</sup>
4.000% senior notes due 2025	February 15 <sup>th</sup> and August 15 <sup>th</sup>
4.875% senior notes due 2025	June 1 <sup>st</sup> and December 1 <sup>st</sup>
4.125% senior notes due 2027	March 1 <sup>st</sup> and September 1 <sup>st</sup>
5.200% senior notes due 2047	March 1 <sup>st</sup> and September 1 <sup>st</sup>

On February 10, 2017, the Partnership completed a public offering of \$1.25 billion aggregate principal amount of 4.125 percent unsecured senior notes due March 2027 (the “2027 Senior Notes”) and \$1.0 billion aggregate principal amount of 5.200 percent unsecured senior notes due March 2047 (the “2047 Senior Notes”). The 2027 Senior Notes and the 2047 Senior Notes were offered at a price to the public of 99.834 percent and 99.304 percent of par, respectively. The net proceeds were used to fund the \$1.5 billion cash portion of the consideration paid to MPC for the dropdown of assets on March 1, 2017, as well as for general partnership purposes.

### **SMR Transaction**

On September 1, 2009, MarkWest completed the sale of the SMR (the “SMR Transaction”). At that time, MarkWest had begun constructing the SMR at its Javelina gas processing and fractionation complex in Corpus Christi, Texas. Under the terms of the agreement, MarkWest received proceeds of \$73 million and the purchaser completed the construction of the SMR. MarkWest and the purchaser also executed a related product supply agreement under which the Partnership will receive the entire product produced by the SMR through 2030 in exchange for processing fees and the reimbursement of certain other expenses. The processing fee payments began when the SMR commenced operations in March 2010. MarkWest was deemed to have continuing involvement with the SMR as a result of certain provisions in the related agreements. Therefore, the transaction is treated as a financing arrangement under GAAP. The Partnership imputes interest on the SMR liability at 6.39 percent annually, its incremental borrowing rate at the time of the purchase accounting valuation. Each processing fee payment has multiple elements: reduction of principal of the SMR liability, interest expense associated with the SMR liability and facility expense related to the operation of the SMR. As part of purchase accounting, the SMR Transaction has been recorded at fair value. As of December 31, 2017 and 2016, the following amounts related to the SMR are included in the accompanying Consolidated Balance Sheets:

<u>(In millions)</u>	<u>December 31, 2017</u>	<u>December 31, 2016</u>
<b>Assets</b>		
Property, plant and equipment, net	\$56	\$61
<b>Liabilities</b>		
Accrued liabilities	5	5
Deferred credits and other liabilities	86	91



## 18. Goodwill and Intangibles

### *Goodwill*

The Partnership annually evaluates goodwill for impairment as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit with goodwill is less than its carrying amount. The Partnership has performed its annual impairment tests, and no additional impairments in the carrying value of goodwill were identified in the periods presented.

During the first quarter of 2016, the Partnership determined that an interim impairment analysis of the goodwill recorded in connection with the MarkWest Merger was necessary based on consideration of a number of first quarter events and circumstances, including i) continued deterioration of near term commodity prices as well as longer term pricing trends, ii) recent guidance on reductions to forecasted capital spending, the slowing of drilling activity and the resulting reduced production growth forecasts released or communicated by the Partnership's producer customers and iii) increases in cost of capital. The combination of these factors was considered to be a triggering event requiring an interim impairment test. Based on the first step of the interim goodwill impairment analysis, the fair value for the three reporting units to which goodwill was assigned in connection with the MarkWest Merger was less than the respective carrying value. In step two of the impairment analysis, the implied fair values of the goodwill were compared to the carrying values within those reporting units. Based on this assessment, it was determined that goodwill was impaired in two of the three reporting units. Accordingly, the Partnership recorded an impairment charge of approximately \$129 million in the first quarter of 2016. In the second quarter of 2016, the Partnership completed its purchase price allocation, which resulted in an additional \$1 million of impairment expense that would have been recorded in the first quarter of 2016 had the purchase price allocation been completed as of that date. This adjustment to the impairment expense was the result of completing an evaluation of the deferred tax liabilities associated with the MarkWest Merger and their impact on the resulting goodwill that was recognized.

The fair value of the reporting units for the interim goodwill impairment analysis was determined based on applying the discounted cash flow method, which is an income approach, and the guideline public company method, which is a market approach. The discounted cash flow fair value estimate is based on known or knowable information at the interim measurement date. The significant assumptions that were used to develop the estimates of the fair values under the discounted cash flow method included management's best estimates of the expected future results and discount rates, which range from 10.5 percent to 11.5 percent. The fair value of the intangibles was determined based on applying the multi-period excess earnings method, which is an income approach. Key assumptions included attrition rates by reporting unit ranging from 5.0 percent to 10.0 percent and discount rates by reporting unit ranging from 11.5 percent to 12.8 percent. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of the interim goodwill impairment test will prove to be an accurate prediction of the future. The fair value measurements for the individual reporting units' overall fair values, and the fair values of the goodwill assigned thereto, represent Level 3 measurements.

The changes in carrying amount of goodwill were as follows for the periods presented:

<i>(In millions)</i>	<u>L&amp;S</u>	<u>G&amp;P</u>	<u>Total</u>
Gross goodwill as of December 31, 2015	\$141	\$2,454	\$2,595
Accumulated impairment losses	—	—	—
Balance as of December 31, 2015	141	2,454	2,595
Purchase price allocation adjustments <sup>(1)</sup>	—	(241)	(241)
Impairment losses	—	(130)	(130)
Acquisitions from MPC	21	—	21
Balance as of December 31, 2016	162	2,083	2,245
Impairment losses	—	—	—
Acquisitions	—	—	—
Balance as of December 31, 2017	<u>\$162</u>	<u>\$2,083</u>	<u>\$2,245</u>
Gross goodwill as of December 31, 2017	\$162	\$2,213	\$2,375
Accumulated impairment losses	—	(130)	(130)
Balance as of December 31, 2017	<u>\$162</u>	<u>\$2,083</u>	<u>\$2,245</u>

<sup>(1)</sup> See Note 4 for further discussion on purchase price allocation adjustments.

### ***Intangible Assets***

The Partnership's intangible assets as of December 31, 2017 and 2016 are comprised of customer contracts and relationships, as follows:

<i>(In millions)</i>	Useful Life	December 31, 2017			December 31, 2016		
		Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
L&S	N/A	\$—	\$—	\$—	\$—	\$—	\$—
G&P	11-25 years	533	(80)	453	533	(41)	492
		<u>\$ 533</u>	<u>\$ (80)</u>	<u>\$ 453</u>	<u>\$ 533</u>	<u>\$ (41)</u>	<u>\$ 492</u>

Estimated future amortization expense related to the intangible assets at December 31, 2017 is as follows:

<i>(In millions)</i>	
2018	\$ 38
2019	38
2020	38
2021	38
2022	38
Thereafter	263
Total	<u>\$453</u>

## 19. Supplemental Cash Flow Information

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Net cash provided by operating activities included:			
Interest paid (net of amounts capitalized)	\$ 263	\$ 213	\$ 13
Income taxes paid	3	4	—
Non-cash investing and financing activities:			
Net transfers of property, plant and equipment from materials and supplies inventories	\$ 6	\$ (3)	\$ 5
Contribution—fixed assets to joint venture <sup>(1)</sup>	337	—	—
Contribution—common units issued <sup>(2)</sup>	1,133	669	—
Acquisition:			
Fair value of MPLX LP units issued <sup>(3)</sup>	—	—	7,326
Payable to seller	—	—	50

<sup>(1)</sup> Contribution of assets to Sherwood Midstream and Sherwood Midstream Holdings. See Note 4.

<sup>(2)</sup> For 2016, includes limited partner units issued to MPC as consideration in the acquisition of HSM. For 2017, includes limited and general partner units issued to MPC as consideration in the acquisitions of the joint-interests, HST, WHC and MPLXT. See Note 4.

<sup>(3)</sup> Limited partner units issued as consideration in the MarkWest Merger. See Note 4.

Net cash used for financing activities also includes \$4.1 million of debt issuance costs incurred to enter into a commitment letter for a \$4.1 billion 364-day term loan. This term loan had not yet been drawn upon as of December 31, 2017. See Note 24.

At December 31, 2017, *Payables—related parties* per the Consolidated Balance Sheets included an \$11 million payable to MPC for distributions of cash received from Joint-Interest Acquisition entities that did not affect cash.

The Consolidated Statements of Cash Flows exclude changes to the Consolidated Balance Sheets that did not affect cash. The following is the change of additions to property, plant and equipment related to capital accruals:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Increase (decrease) in capital accruals	\$ 71	\$ (22)	\$ 27

## 20. Equity-Based Compensation

### *Description of the Plan*

The MPLX LP 2012 Incentive Compensation Plan (“MPLX 2012 Plan”) authorizes the MPLX GP board of directors (the “Board”) to grant unit options, unit appreciation rights, restricted units and phantom units, distribution equivalent rights, unit awards, profits interest units, performance units and other unit-based awards to the Partnership’s or any of its affiliates’ employees, officers and directors, including directors and officers of MPC. No more than 2.75 million MPLX LP common limited partner units may be delivered under the MPLX 2012 Plan. Units delivered pursuant to an award granted under the MPLX 2012 Plan may be funded through acquisition on the open market, from the Partnership or from an affiliate of the Partnership, as determined by the Board.

### *Unit-based Awards under the Plan*

The Partnership expenses all unit-based payments to employees and non-employee directors based on the grant date fair value of the awards over the requisite service period, adjusted for estimated forfeitures.

*Phantom Units*—The Partnership grants phantom units under the MPLX 2012 Plan to non-employee directors of MPLX LP’s general partner and of MPC. Awards to non-employee directors are accounted for as non-employee awards. Phantom units granted to non-employee directors vest immediately at the time of the grant, as they are non-forfeitable, but are not issued until the director’s departure from the board of directors. Prior to issuance, non-employee directors do not have the right to vote such units and cash distribution equivalents accrue in the form of additional phantom units and will be issued when the director departs from the board of directors.

The Partnership grants phantom units under the MPLX 2012 Plan to certain officers and non-officers of MPLX LP, MPLX LP’s general partner and MPC who make significant contributions to our business. These grants are accounted for as employee awards. In general, these phantom units will vest over a requisite service period of up to three years. Prior to vesting, these phantom unit recipients will not have the right to vote such units and cash distributions declared will be accrued and paid upon vesting. The accrued distributions at December 31, 2017 and 2016 were \$4 million and \$2 million, respectively.

The fair values of phantom units are based on the fair value of MPLX LP common limited partner units on the grant date.

*Performance Units*—The Partnership grants performance units under the MPLX 2012 Plan to certain officers of the general partner and certain eligible MPC officers who make significant contributions to its business. These awards are intended to have a per unit payout determined by the total unitholder return of MPLX LP common units as compared to the total unitholder return of a selected group of peer partnerships. The final per unit payout will be the average of the results of four measurement periods during the 36 month requisite service period. These performance units will pay out 75 percent in cash and 25 percent in MPLX LP common units. The performance units paying out in cash are accounted for as liability awards and recorded at fair value with a mark-to-market adjustment made each quarter. The performance units paying out in units are accounted for as equity awards. The performance units granted in 2017 are hybrid awards having a three-year performance period of January 1, 2017 through December 31, 2019. The payout of the award is dependent on two independent conditions, each constituting 50 percent of the overall target units granted. The awards have a performance condition based on MPLX LP’s DCF during the last twelve months of the performance period, and a market condition based on MPLX LP’s total unitholder return over the entire three-year performance period. The performance units paying out in units have a weighted average grant date fair value of \$0.90 per unit for 2017 and \$0.63 per unit for 2016, as calculated using a Monte Carlo valuation model.

### ***Outstanding Phantom Unit Awards***

The following is a summary of phantom unit award activity of MPLX LP common limited partner units in 2017:

	Phantom Units		
	Number of Units	Weighted Average Fair Value	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2016	1,173,411	\$33.09	
Granted	716,587	36.26	
Settled	(419,953)	33.45	
Forfeited	(118,522)	34.57	
Outstanding at December 31, 2017	<u>1,351,523</u>	34.53	
Vested and expected to vest at December 31, 2017	1,326,940	34.52	\$47
Convertible at December 31, 2017	356,400	34.57	\$13

The 356,400 convertible units are held by our non-employee directors and certain officers. These units are non-forfeitable and issuable upon the holder’s departure from service to the company.

The following is a summary of the values related to phantom units held by officers and non-employee directors:

	Phantom Units	
	Intrinsic Value of Units Issued During the Period (in millions)	Weighted Average Grant Date Fair Value of Units Granted During the Period
2017	\$15	\$36.26
2016	5	29.42
2015	3	35.00

As of December 31, 2017, unrecognized compensation cost related to phantom unit awards was \$25 million, which is expected to be recognized over a weighted average period of 1.9 years.

### ***Outstanding Performance Unit Awards***

The following table presents a summary of the 2017 activity for performance unit awards to be settled in MPLX LP common units:

	Performance Units	
	Number of Units	Weighted Average Fair Value
Outstanding at December 31, 2016	1,799,249	\$0.89
Granted	1,407,062	0.90
Settled	(464,500)	1.16
Forfeited	(205,217)	0.89
Outstanding at December 31, 2017	<u>2,536,594</u>	0.85

The number of limited partner units that would be issued upon target vesting, using the closing price of our units on December 31, 2017 would be 71,514 units.

As of December 31, 2017, unrecognized compensation cost related to equity-classified performance unit awards was \$1 million, which is expected to be recognized over a weighted average period of 1.8 years.

Performance units paying out in MPLX LP common units have a grant date fair value calculated using a Monte Carlo valuation model, which requires the input of subjective assumptions. The following table provides a summary of the weighted average inputs used for these assumptions:

	2017	2016	2015
Risk-free interest rate	1.52%	0.96%	0.95%
Look-back period	2.83 years	2.83 years	2.84 years
Expected volatility	49.34%	47.59%	30.12%
Grant date fair value of performance units granted	\$ 0.90	\$ 0.63	\$ 1.03

The assumption for expected volatility of our unit price reflects the historical volatility of MPLX LP common units. The look-back period reflects the remaining performance period at the grant date. The risk-free interest rate for the remaining performance period as of the grant date is based on the U.S. Treasury yield curve in effect at the time of the grant.

### ***Total Unit-Based Compensation Expense***

Total unit-based compensation expense for awards settling in MPLX LP common units was \$18 million in 2017, \$10 million in 2016 and \$4 million in 2015. Approximately \$15 million was charged to the MarkWest purchase price in 2015 for MPLX LP unit-based compensation awards granted in connection with the MarkWest Merger.

### *MPC's Stock-based Compensation*

Stock-based compensation expenses charged to MPLX LP under our employee services agreement with MPC were \$2 million, \$5 million and \$1 million for 2017, 2016 and 2015, respectively.

### **21. Lease Operations**

Based on the terms of certain natural gas gathering, transportation and processing agreements, the Partnership is considered to be the lessor under several implicit operating lease arrangements in accordance with GAAP. The Partnership's primary implicit lease operations relate to a natural gas gathering agreement in the Marcellus Shale for which it earns a fixed-fee for providing gathering services to a single producer using a dedicated gathering system. As the gathering system is expanded, the fixed-fee charged to the producer is adjusted to include the additional gathering assets in the lease. The primary term of the natural gas gathering arrangement expires in 2023 and will continue thereafter on a year-to-year basis until terminated by either party. Other significant implicit leases relate to a natural gas processing agreement in the Marcellus Shale and a natural gas processing agreement in the Southern Appalachia region for which the Partnership earns minimum monthly fees for providing processing services to a single producer using a dedicated processing plant. The primary term of these natural gas processing agreements expires during 2023 and 2032.

Based on the terms of the Partnership's fee-based transportation services and storage services agreements with MPC, the Partnership is also considered to be a lessor of its pipelines, marine equipment and storage facilities in accordance with GAAP. The Partnership's revenue from its implicit lease arrangements, excluding executory costs, totaled approximately \$601 million in 2017, \$586 million in 2016 and \$127 million in 2015.

The Partnership's implicit lease arrangements related to the processing facilities contain contingent rental provisions whereby the Partnership receives additional fees if the producer customer exceeds the monthly minimum processed volumes. During the years ended December 31, 2017 and 2016, the Partnership received \$9 million and \$7 million, respectively, in contingent lease payments.

The following is a schedule of minimum future rental revenue on the non-cancellable operating leases as of December 31, 2017:

<i>(In millions)</i>	<u>Related Party</u>	<u>Third Party</u>	<u>Total</u>
2018	\$ 247	\$ 194	\$ 441
2019	242	194	436
2020	247	193	440
2021	135	181	316
2022	137	172	309
2023 and thereafter	<u>535</u>	<u>320</u>	<u>855</u>
Total minimum future rentals	<u>\$1,543</u>	<u>\$1,254</u>	<u>\$2,797</u>

The following schedule summarizes the Partnership's investment in assets held for operating lease by major classes as of December 31, 2017 and 2016:

<u>(In millions)</u>	December 31,	
	2017	2016
Natural gas gathering and NGL transportation pipelines and facilities	\$ 735	\$ 650
Processing, fractionation and storage facilities <sup>(1)</sup>	733	924
Pipelines and related assets	253	307
Barges and towing vessels <sup>(1)</sup>	491	479
Terminals and related assets <sup>(1)</sup>	822	759
Construction-in-progress	85	275
Total	<u>3,119</u>	<u>3,394</u>
Less accumulated depreciation	<u>(1,056)</u>	<u>(843)</u>
Property, plant and equipment, net	<u>\$ 2,063</u>	<u>\$2,551</u>

(1) Certain prior period amounts have been updated to conform to current period presentation.

## 22. Asset Retirement Obligations

The Partnership's assets subject to AROs are primarily certain gas-gathering pipelines and processing facilities, a crude oil pipeline and other related pipeline assets. The Partnership also has land leases that require the Partnership to return the land to its original condition upon termination of the lease. The Partnership reviews current laws and regulations governing obligations for asset retirements and leases, as well as the Partnership's leases and other agreements.

The following is a reconciliation of the changes in the ARO from January 1, 2016 to December 31, 2017:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>
ARO at beginning of period	\$ 25	\$17
Liabilities incurred	2	8
Adjustments to AROs	—	(1)
Accretion expense	<u>1</u>	<u>1</u>
ARO at end of period	<u>\$ 28</u>	<u>\$25</u>

At December 31, 2017 and 2016, there were no assets legally restricted for purposes of settling AROs. The AROs have been recorded as part of *Deferred credits and other liabilities* in the accompanying Consolidated Balance Sheets.

In addition to recorded AROs, the Partnership has other AROs related to certain gathering, processing and other assets as a result of environmental and other legal requirements. The Partnership is not required to perform such work until it permanently ceases operations of the respective assets. Because the Partnership considers the operational life of these assets to be indeterminable, an associated ARO cannot be estimated and is not recorded.

## 23. Commitments and Contingencies

The Partnership is the subject of, or a party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. Some of these matters are discussed below. For matters for which the Partnership has not recorded an accrued liability, the Partnership is unable to estimate a range of possible losses for the reasons discussed in more detail below. However, the ultimate resolution of some of these contingencies could, individually or in the aggregate, be material.

***Environmental Matters***—The Partnership is subject to federal, state and local laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for non-compliance.

At December 31, 2017 and 2016, accrued liabilities for remediation totaled \$13 million and \$3 million, respectively. However, it is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties, if any, which may be imposed. At December 31, 2016, there was less than \$1 million in receivables from MPC for indemnification of environmental costs related to incidents occurring prior to the Initial Offering. At December 31, 2017, there was less than \$1 million in payables to MPC for these costs.

In July 2015, representatives from the EPA and the United States Department of Justice conducted a search at a MarkWest Liberty Midstream pipeline launcher/receiver site utilized for pipeline maintenance operations in Washington County, Pennsylvania pursuant to a search warrant. The criminal investigation ended without any charges against MarkWest Liberty Midstream. With respect to the civil enforcement allegations associated with permitting or other related regulatory obligations for its launcher/receiver and compressor station facilities in the region, MarkWest Liberty Midstream and its affiliates have agreed in principle to pay a cash penalty of approximately \$0.6 million and to undertake certain supplemental environmental projects with an estimated cost of approximately \$2.4 million.

The Partnership is involved in a number of other environmental enforcement matters arising in the ordinary course of business. While the outcome and impact on MPLX LP cannot be predicted with certainty, management believes the resolution of these environmental matters will not, individually or collectively, have a material adverse effect on its consolidated results of operations, financial position or cash flows.

***Other Lawsuits***—The Partnership, MarkWest, MarkWest Liberty Midstream, MarkWest Liberty Bluestone, L.L.C., Ohio Fractionation and MarkWest Utica EMG (collectively, the “MPLX Parties”) are parties to various lawsuits with Bilfinger Westcon, Inc. (“Westcon”) that were instituted in 2016 and 2017 in the Court of Common Pleas in Butler County, Pennsylvania, the Circuit Court in Wetzel County, West Virginia, and the Court of Common Pleas in Harrison County, Ohio. The lawsuits relate to disputes regarding construction work performed by Westcon at the Bluestone, Mobley and Cadiz processing complexes in Pennsylvania, West Virginia and Ohio, respectively, and the Hopedale fractionation complex in Ohio. With respect to work performed by Westcon at the Mobley and Bluestone processing complexes, one or more of the MPLX Parties have asserted breach of contract, fraud, and with respect to work performed at the Mobley processing complex, MarkWest Liberty Midstream has also asserted negligent misrepresentation claims against Westcon. Westcon has also asserted claims against one or more of the MPLX Parties regarding these construction projects for breach of contract, unjust enrichment, promissory estoppel, fraud and constructive fraud, tortious interference with contractual relations, and civil conspiracy. The MPLX Parties seek in excess of \$10 million, plus an unspecified amount of punitive damages. Westcon seeks in excess of \$40 million, plus an unspecified amount of punitive damages. It is possible that, in connection with these lawsuits, the MPLX Parties will incur material amounts of damages. While the ultimate outcome and impact to the Partnership cannot be predicted with certainty, and the Partnership is not able to provide a reasonable estimate of the potential loss (or range of loss), if any, for these claims, the Partnership believes the resolution of these claims will not have a material adverse effect on its consolidated financial position, results of operations, or cash flows.

In 2003, the State of Illinois brought an action against the Premcor Refining Group, Inc. (“Premcor”) and Apex Refining Company (“Apex”) asserting claims for environmental cleanup related to the refinery owned by these entities in the Hartford/Wood River, Illinois area. In 2006, Premcor and Apex filed third-party complaints against numerous owners and operators of petroleum products facilities in the Hartford/Wood River, Illinois area, including Marathon Pipe Line LLC (“MPL”). These complaints, which have been amended since filing, assert claims of common law nuisance and contribution under the Illinois Contribution Act and other laws for



environmental cleanup costs that may be imposed on Premcor and Apex by the State of Illinois. On September 6, 2016, the trial court approved a settlement between Apex and the State of Illinois whereby Apex agreed to settle all claims against it for a \$10 million payment. Premcor has objected to this ruling and is seeking an appeal. There are several third-party defendants in the litigation and MPL has asserted cross-claims in contribution against the various third-party defendants. This litigation is currently pending in the Third Judicial Circuit Court, Madison County, Illinois. The State's case against Premcor is currently scheduled to commence trial on June 25, 2018, and Premcor's claims against third-party defendants, including MPL, is currently scheduled to commence August 13, 2018. While the ultimate outcome of these litigated matters remains uncertain, neither the likelihood of an unfavorable outcome nor the ultimate liability, if any, with respect to this matter can be determined at this time and the Partnership is unable to estimate a reasonably possible loss (or range of loss) for this litigation. Under the omnibus agreement, MPC will indemnify the Partnership for the full cost of any losses should MPL be deemed responsible for any damages in this lawsuit. The Partnership is also a party to a number of other lawsuits and other proceedings arising in the ordinary course of business. While the ultimate outcome and impact to the Partnership cannot be predicted with certainty, the Partnership believes the resolution of these other lawsuits and proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

**Guarantees**—Over the years, the Partnership has sold various assets in the normal course of its business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require the Partnership to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. The Partnership is typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

**Contractual Commitments and Contingencies**—At December 31, 2017, the Partnership's contractual commitments to acquire property, plant and equipment totaled \$355 million. These commitments were primarily related to plant expansion projects for the Marcellus and Southwest Operations. In addition, from time to time and in the ordinary course of business, the Partnership and its affiliates provide guarantees of the Partnership's subsidiaries payment and performance obligations in the G&P segment. Certain natural gas processing and gathering arrangements require the Partnership to construct new natural gas processing plants, natural gas gathering pipelines and NGL pipelines and contain certain fees and charges if specified construction milestones are not achieved for reasons other than force majeure. In certain cases, certain producers may have the right to cancel the processing arrangements if there are significant delays that are not due to force majeure. As of December 31, 2017, management does not believe there are any indications that the Partnership will not be able to meet the construction milestones, that force majeure does not apply or that such fees and charges will otherwise be triggered.

**Lease and Other Contractual Obligations**—The Partnership executed transportation and terminalling agreements that obligate us to minimum volume, throughput or payment commitments over the terms of the agreements, which range from three to ten years. After the minimum volume commitments are met in the transportation and terminalling agreements, the Partnership pays additional amounts based on throughput. There are escalation clauses in the transportation and terminalling agreements, which are based on CPI adjustments. The minimum future payments under these agreements as of December 31, 2017 are as follows:

<u>(In millions)</u>	
2018	\$ 52
2019	61
2020	62
2021	62
2022	62
2023 and thereafter	<u>275</u>
Total	<u>\$574</u>

The Partnership has various non-cancellable operating lease agreements and a long-term propane storage agreement expiring at various times through fiscal year 2040. Most of these leases include renewal options. The Partnership also leases certain pipelines under a capital lease that has a fixed price purchase option in 2020. Future minimum commitments as of December 31, 2017, for capital lease obligations and for operating lease obligations having initial or remaining non-cancellable lease terms in excess of one year are as follows:

<u>(In millions)</u>	<u>Capital Lease Obligations</u>	<u>Operating Lease Obligations</u>
2018	\$ 1	\$ 54
2019	2	42
2020	5	37
2021	—	34
2022	—	28
Later years	<u>—</u>	<u>54</u>
Total minimum lease payments	8	<u>\$249</u>
Less: imputed interest costs	<u>1</u>	
Present value of net minimum lease payments	<u>\$ 7</u>	

Operating lease rental expense was:

<u>(In millions)</u>	<u>2017</u>	<u>2016</u>	<u>2015</u>
Minimum rental expense	\$64	\$57	\$ 21

**SMR Transaction**—On September 1, 2009, MarkWest entered into a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for the entire product processed by the SMR. See Note 17 for additional discussion. The product received under this agreement is sold to a refinery customer pursuant to a corresponding long-term agreement. The minimum amounts payable annually under the product supply agreement, excluding the potential impact of inflation adjustments per the agreement, are as follows:

<i>(In millions)</i>	
2018	\$ 17
2019	17
2020	17
2021	17
2022	17
2023 and thereafter	<u>126</u>
Total minimum payments	211
Less: Services element	80
Less: Interest	<u>40</u>
Total SMR liability	91
Less: Current portion of SMR liability	<u>5</u>
Long-term portion of SMR liability	<u><u>\$ 86</u></u>

#### 24. Subsequent Events

On February 1, 2018, MPC and MPLX LP closed on an agreement for the dropdown of refining logistics assets and fuels distribution services to MPLX LP. MPC contributed these assets and services in exchange for \$4.1 billion in cash and MPLX LP issued 111.6 million common units and 2.3 million general partner units to maintain MPC's two percent GP interest.

Immediately following the dropdown, MPC exchanged its economic GP interest in MPLX LP, which included IDRs, for 275 million newly issued MPLX LP common units. MPC continues to own the non-economic GP interest in MPLX LP. For purposes of calculating year to date net income attributable to MPLX LP per unit for 2017, any fourth quarter distributions declared on the GP common units resulting from this transaction were allocated to the economic GP interests to align with the weighted shares outstanding at December 31, 2017. See Note 7 for more information on the net income per unit calculation.

On January 2, 2018, the Partnership entered into a term loan agreement with a syndicate of lenders providing for a \$4.1 billion, 364-day term loan facility. The Partnership drew the entire amount of the term loan facility in a single borrowing on February 1, 2018. The proceeds from the term loan facility were used to fund the cash portion of the dropdown consideration.

On February 8, 2018, the Partnership issued \$5.5 billion of senior notes in a public offering, consisting of \$500 million aggregate principal amount of 3.375 percent unsecured senior notes due March 2023, \$1.25 billion aggregate principal amount of 4.0 percent unsecured senior notes due March 2028, \$1.75 billion aggregate principal amount of 4.5 percent unsecured senior notes due April 2038, \$1.5 billion aggregate principal amount of 4.7 percent unsecured senior notes due April 2048, and \$500 million aggregate principal amount of 4.9 percent unsecured senior notes due April 2058. The notes were offered at a price to the public of 99.931 percent, 99.551 percent, 98.811 percent, 99.348 percent, and 99.289 percent of par, respectively. On February 8, 2018, \$4.1 billion of the net proceeds were used to repay the 364-day term loan facility, which was drawn on February 1, 2018, to fund the cash portion of the consideration MPLX paid MPC for the dropdown of assets on February 1, 2018. The remaining proceeds were used to repay outstanding borrowings under the MPLX Credit

Agreement and the intercompany loan agreement with MPC Investment, as well as for general partnership purposes.

**Select Quarterly Financial Data (Unaudited)**

<i>(In millions, except per unit data)</i>	2017				2016			
	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr. <sup>(1)</sup>	2nd Qtr. <sup>(2)</sup>	3rd Qtr.	4th Qtr.
Total revenues and other income	\$ 886	\$ 916	\$ 980	\$ 1,085	\$ 645	\$ 698	\$ 838	\$ 848
Income from operations	265	280	311	335	50	128	258	247
Net income (loss)	187	191	217	241	(14)	72	194	182
Net income (loss) attributable to MPLX LP	150	190	216	238	(60)	19	141	133
Net income (loss) attributable to MPLX LP per limited partner unit:								
Common—basic	\$ 0.20	\$ 0.26	\$ 0.29	\$ 0.31	\$ (0.33)	\$ (0.11)	\$ 0.22	\$ 0.17
Common—diluted	0.19	0.26	0.29	0.31	(0.33)	(0.11)	0.21	0.17
Subordinated—basic and diluted	—	—	—	—	—	—	—	—
Cash distributions declared per limited partner common unit	\$0.5400	\$0.5625	\$0.5875	\$0.6075	\$0.5050	\$0.5100	\$0.5150	\$0.5200
<b>Distributions declared:</b>								
Limited partner units—Public	\$ 149	\$ 162	\$ 170	\$ 175	\$ 127	\$ 131	\$ 135	\$ 140
Limited partner units—MPC	47	51	54	58	29	41	44	45
General partner units—MPC	5	6	7	—	4	4	5	5
Limited partner units—GP	2	5	8	113	—	—	—	—
IDRs—MPC	60	70	81	—	40	46	49	52
Redeemable preferred units	16	17	16	16	—	9	16	16
<b>Total distributions declared</b>	<b>\$ 279</b>	<b>\$ 311</b>	<b>\$ 336</b>	<b>\$ 362</b>	<b>\$ 200</b>	<b>\$ 231</b>	<b>\$ 249</b>	<b>\$ 258</b>

(1) First quarter 2016 results included goodwill impairment expense of \$129 million. See Note 18 for more information.

(2) Second quarter 2016 results included impairment expense related to equity method investments of \$89 million. See Note 5 for more information.

## **Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures**

None

### **Item 9A. Controls and Procedures**

#### **Disclosure Controls and Procedures**

The Partnership's management, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 Act, as amended, as of December 31, 2017. Based on this evaluation, the Partnership's management, including our Chief Executive Officer and Chief Financial Officer, concluded that as of December 31, 2017, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 Act, as amended, is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

#### **Internal Control Over Financial Reporting and Changes in Internal Control Over Financial Reporting**

During the three months ended December 31, 2017, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. See Item 8. Financial Statements and Supplementary Data—Management's Report on Internal Control over Financial Reporting.

#### **Limitations on Controls**

Management has designed our disclosure controls and procedures and internal control over financial reporting to provide reasonable assurance of achieving their objectives as specified above. Management does not expect, however, that our disclosure controls and procedures or our internal control over financial reporting will prevent or detect all error and fraud. Any control system, no matter how well designed and operated, is based upon certain assumptions and can provide only reasonable, not absolute, assurance that its objectives will be met. Further, no evaluation of controls can provide absolute assurance that misstatements due to error or fraud will not occur or that management has detected all control issues and instances of fraud, if any, within the Partnership.

### **Item 9B. Other Information**

None

## **Part III**

### **Item 10. Directors, Executive Officers and Corporate Governance**

#### **MANAGEMENT OF MPLX LP**

We are managed by the directors and executive officers of our general partner, MPLX GP LLC. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. MPC indirectly owns all of the membership interests in our general partner. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or directly or indirectly to participate in our management or operations. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, we intend to incur indebtedness that is non-recourse to our general partner.

The board of directors of our general partner has twelve members. MPC appoints all members to the board of directors of our general partner, which we may refer to as our board. Our board has determined that each of Michael L. Beatty, David A. Daberko, Christopher A. Helms, Garry L. Peiffer, Dan D. Sandman and John P. Surma meets the independence standards in our Governance Principles, has no material relationship with the Partnership other than that arising solely from the capacity as a director and, in addition, satisfies the independence requirements of the NYSE, including the NYSE independence standards applicable to the committees on which each such director serves. Mr. Wilson, who retired from the board of directors of our general partner effective December 31, 2017, also met the independence standards referred to in the preceding sentence during his service on the board in 2017. In making its determinations, our board considered that Mr. Helms serves on the board of directors of Range Resources Corporation. During 2017, MPLX LP provided gathering, processing and NGL fractionation services to Range Resources, and certain affiliates of our general partner purchased natural gas from Range Resources. The relationship with Range Resources was entered into in the ordinary course of business on arms-length terms in amounts and under circumstances that did not affect Mr. Helms's independence under our Governance Principles or under applicable law and NYSE listing standards.

Neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the employees and other personnel necessary to conduct our operations. All of the employees who conduct our business are employed by affiliates of our general partner, but we sometimes refer to these individuals as our employees for ease of reference.

#### **Director Independence**

Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a publicly traded limited partnership like us to have a majority of independent directors on our board or to establish a compensation or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members, and all of our audit committee members are required to meet the independence and financial literacy tests established by the NYSE and the Exchange Act.

#### **Committees of the Board of Directors**

Our board has an audit committee and a conflicts committee, and may have such other committees as the board shall determine from time to time. The audit committee and the conflicts committee are comprised entirely of independent directors. Additionally, an executive committee of the board, comprised of Gary R. Heminger and Dan D. Sandman, has been established to address matters that may arise between meetings of the board. This executive committee may exercise the powers and authority of the board subject to specific limitations consistent with applicable law.

Each of the standing committees of the board of directors has the composition and responsibilities described below.

## **Audit Committee**

Garry L. Peiffer serves as the chairman, and Michael L. Beatty, Christopher A. Helms and Dan D. Sandman are members, of our audit committee. Our audit committee assists the board of directors in its oversight of the integrity of our financial statements, and our compliance with legal and regulatory requirements and our disclosure controls and procedures. Our audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. Our audit committee also is responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to our audit committee.

Our audit committee has a written charter adopted by the board of directors of our general partner, which is available on our website at <http://ir.mplx.com> by selecting “Corporate Governance” and clicking on “Board Committees and Charters,” “Audit Committee,” “Audit Committee Charter.” The audit committee charter requires our audit committee to assess and report to the board on the adequacy of the charter on an annual basis. Each of the members of our audit committee is independent as independence is defined in the Exchange Act, and also satisfies the general independence requirements of the NYSE.

## **Audit Committee Financial Expert**

Based on the attributes, education and experience requirements set forth in the rules of the SEC, the board of directors of our general partner has determined that Christopher A. Helms and Garry L. Peiffer each qualify as an “Audit Committee Financial Expert.”

Mr. Helms served in various capacities at NiSource Inc. and its affiliate, NiSource Gas Transmission and Storage, including as executive vice president and group chief executive officer and group president, Pipeline of NiSource Inc., where he was also a member of the executive council and corporate risk management committee. He also served as chief executive officer and executive director of NiSource Gas Transmission and Storage and has extensive experience in the areas of finance, accounting, compliance, strategic planning and risk oversight. Mr. Helms has served on the finance and audit committee of another public company.

Mr. Peiffer previously served as the controller and assistant controller of various MPC divisions and was senior vice president of Finance and Commercial Services of Marathon Ashland Petroleum LLC and its successors for more than a decade. During his various accounting and finance assignments while at MPC, Mr. Peiffer was responsible for preparing financial statements, supervising financial statement preparation, reviewing internal controls and attending audit committee meetings. Mr. Peiffer holds a bachelor’s degree in accounting and passed the certified public accountant exam in Ohio.

### **Audit Committee Report**

The Audit Committee has reviewed and discussed the Partnership's audited financial statements and its report on internal control over financial reporting for 2017 with the management of MPLX GP LLC, the Partnership's general partner. The Audit Committee discussed with the independent auditors, PricewaterhouseCoopers LLP, the matters required to be discussed by the Public Company Accounting Oversight Board's standard, Auditing Standard No. 1301. The Committee has received the written disclosures and the letter from PricewaterhouseCoopers LLP required by the applicable requirements of the Public Company Accounting Oversight Board for independent auditor communications with audit committees concerning independence and has discussed with PricewaterhouseCoopers LLP its independence. Based on the review and discussions referred to above, the Audit Committee recommended to the Board that the audited financial statements and the report on internal control over financial reporting for MPLX LP be included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017, for filing with the SEC.

Garry L. Peiffer, Chairman  
Michael L. Beatty  
Christopher A. Helms  
Dan D. Sandman

### **Conflicts Committee**

Christopher A. Helms serves as the chairman, and Michael L. Beatty and Dan D. Sandman are members, of our conflicts committee. Our conflicts committee reviews specific matters that may involve conflicts of interest in accordance with the terms of our Partnership Agreement. Any matters approved by our conflicts committee in good faith will be deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. The members of our conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. In addition, the members of our conflicts committee may not own any interest in our general partner or any interest in us, our subsidiaries or our affiliates other than common units or awards under our incentive compensation plan.

Our conflicts committee has a written charter adopted by the board of directors of our general partner, which is available on our website at <http://ir.mplx.com> by selecting "Corporate Governance" and clicking on "Board Committees and Charters," "Conflicts Committee," "Conflicts Committee Charter." The conflicts committee charter requires our conflicts committee to assess and report to the board on the adequacy of the charter on an annual basis. Each of the members of our conflicts committee is independent as independence is defined in the Exchange Act, and also satisfies the general independence requirements of the NYSE.



## DIRECTORS AND EXECUTIVE OFFICERS OF MPLX GP LLC

Directors are elected by the sole member of our general partner and hold office until their successors have been elected or qualified or until their earlier death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors. The following table shows information for the directors, and executive and corporate officers of MPLX GP LLC.

Name	Age as of January 31, 2018	Position with MPLX GP LLC
Gary R. Heminger	64	Chairman of the Board of Directors and Chief Executive Officer
Michael J. Hennigan	58	Director and President
Pamela K.M. Beall	61	Director, Executive Vice President and Chief Financial Officer
Michael L. Beatty	70	Director
David A. Daberko	72	Director
Timothy T. Griffith	48	Director
Christopher A. Helms	63	Director
Garry L. Peiffer	66	Director
Dan D. Sandman	69	Director
Frank M. Semple	66	Director
John P. Surma	63	Director
Donald C. Templin	54	Director
Gregory S. Floerke	54	Executive Vice President, Gathering and Processing
John S. Swearingen	58	Executive Vice President, Logistics and Storage
Raymond L. Brooks <sup>(1)</sup>	57	Senior Vice President
Thomas M. Kelley <sup>(1)</sup>	58	Senior Vice President
C. Michael Palmer <sup>(1)</sup>	64	Senior Vice President
Timothy J. Aydt <sup>(1)</sup>	54	Vice President, Operations
Molly R. Benson <sup>(1)</sup>	51	Vice President, Corporate Secretary and Chief Compliance Officer
Suzanne Gagle	52	Vice President and General Counsel
Peter Gilgen <sup>(1)</sup>	61	Vice President and Treasurer
C. Kristopher Hagedorn	41	Vice President and Controller

<sup>(1)</sup> Corporate officer.

*Gary R. Heminger.* Gary R. Heminger was appointed chief executive officer and elected chairman of the board of directors of our general partner in June 2012. He is also chairman of the board and chief executive officer of MPC, and a member of the boards of directors of Fifth Third Bancorp and PPG Industries, Inc. Mr. Heminger began his career with Marathon in 1975 and has served in a variety of capacities. In addition to holding various finance and administration roles, he spent three years in London as part of the Brae Project and served in several marketing and commercial positions with Emro Marketing Company, the predecessor of Speedway LLC. He also served as president of Marathon Pipe Line Company. Mr. Heminger was named vice president of Business Development for Marathon Ashland Petroleum LLC upon its formation in 1998, senior vice president in 1999 and executive vice president in 2001. Mr. Heminger was appointed president of Marathon Petroleum Company LLC and executive vice president Marathon Oil Corporation—Downstream in 2001. He was named president and chief executive officer of MPC on July 1, 2011, and was named chairman in 2016. He served as president of MPC from 2011 until 2017. Mr. Heminger is past-chairman of the board of trustees of Tiffin University. He serves on the boards of directors and executive committees of the American Petroleum Institute (API) and the American Fuel & Petrochemicals Manufacturers (AFPM). He also serves on the board of directors of JobsOhio. Mr. Heminger is a member of the Oxford Institute for Energy Studies. Mr. Heminger earned a bachelor's degree in accounting from Tiffin University in 1976 and a master's degree in business administration from the University of Dayton, Ohio, in 1982. He is a graduate of the Wharton School Advanced Management Program at the University of Pennsylvania.

*Qualifications:* Mr. Heminger has extensive knowledge of all aspects of our business. As our chief executive officer, he leverages that expertise in advising on the strategic direction of the Partnership and apprising the board on issues of significance to the Partnership and our industry. Mr. Heminger also serves on two outside public company boards of directors, which affords him a fresh perspective on management and governance. Mr. Heminger brings to our board energy industry expertise and a breadth of transactional experience.

*Other Public Company Directorships:* Marathon Petroleum Corporation (2011 to present); Fifth Third Bancorp (2006 to present); PPG Industries, Inc. (2017 to present)

*Michael J. Hennigan.* Michael J. Hennigan was appointed president of our general partner and was elected a member of the board of directors of our general partner in June 2017. Prior to joining our general partner, Mr. Hennigan was president, crude, NGL and refined products of the general partner of Energy Transfer Partners L.P. Prior to that, he served as president and chief executive officer of Sunoco Logistics Partners L.P. where he was responsible for all operations and business activities, including setting the direction, strategy and vision for the company from 2012 until 2017. Mr. Hennigan joined Sunoco Logistics as vice president, business development in 2009. He was named president and chief operating officer in 2010 and was appointed president and chief executive officer in 2012. Mr. Hennigan has 35 years of industry experience. He graduated from Drexel University in 1982 with a bachelor's degree in chemical engineering.

*Qualifications:* With more than 35 years of industry experience, including as the President and CEO of a successful growth-oriented master limited partnership, Mr. Hennigan provides a unique perspective and valued guidance to the board.

*Other Public Company Directorships:* Sunoco Partners LLC (2010 to 2017); Niska Gas Storage Partners LLC (2014 to 2016)

*Pamela K. M. Beall.* Pamela K. M. Beall was elected a member of the board of directors of our general partner in January 2014 and is executive vice president and chief financial officer of our general partner. She also serves on the board of directors of National Retail Properties, Inc., the board of trustees of The University of Findlay, and is a member of The Ohio Society of CPAs. Ms. Beall began her career with Marathon in 1978 as an auditor and held positions with the Corporate Risk and Environmental Affairs and Domestic Funds organizations before transferring to USX Corporation as general manager, Treasury Services. She was vice president and treasurer at NationsRent, Inc. and OHM Corporation, and served on the boards of directors of System One Services, Inc. and Boyle Engineering. Ms. Beall rejoined Marathon in 2002, as manager, Business Development for Marathon Ashland Petroleum LLC. She was named director, Corporate Affairs in 2003 and appointed director, Business Development in 2005. She then served as organizational vice president, Business Development—Downstream for Marathon Petroleum Company LLC in 2006. Ms. Beall was named vice president of Global Procurement for Marathon Oil Company in 2007, vice president of Products, Supply & Optimization for Marathon Petroleum Company LLC in 2010 and vice president, Investor Relations and Government & Public Affairs in 2011. She was named president of our general partner and senior vice president, Corporate Planning, Government and Public Affairs of MPC in 2014. Ms. Beall was named executive vice president, Corporate Planning and Strategy of our general partner and then assumed her current position in 2016. Ms. Beall graduated from The University of Findlay with a bachelor's degree in accounting in 1978. In 1984, she received her master's degree in business administration from Bowling Green State University. Ms. Beall is licensed as a certified public accountant in Ohio. She attended the Oxford Institute for Energy Studies in 2003.

*Qualifications:* As the executive vice president and chief financial officer of our general partner, Ms. Beall has extensive energy industry experience, specifically in the areas of finance and accounting, business development, risk management, procurement, investor relations and government affairs. She has also served as a senior executive in the environmental remediation and industrial products rental sectors, as well as on the boards of directors of other companies. Ms. Beall brings to our board her knowledge of the Partnership's business and operations, and her perspective on its prospects for growth.

*Other Public Company Directorships:* National Retail Properties, Inc. (2016 to present)

*Michael L. Beatty.* Michael L. Beatty was elected a member of the board of directors of our general partner effective December 4, 2015, at the time of the MarkWest Merger in fulfillment of our obligations under the merger agreement with MarkWest to appoint two directors identified by MarkWest to the board of our general partner effective at the close of the merger. Mr. Beatty was a member of the board of directors of MarkWest's general partner from 2008 until the MarkWest Merger, and served on the MarkWest board's nominating and corporate governance committee and compensation committee. He also serves on the board of directors of the Cystic Fibrosis Foundation. Mr. Beatty is a former chairman of the law firm of Beatty & Wozniak, P.C. headquartered in Denver, Colorado, with a practice focused exclusively on energy, including oil and gas exploration, regulatory affairs, public lands, litigation and title. Prior to being appointed to the board of directors of MarkWest Energy Partners, L.P. in 2008, he served as a member of the board of directors of MarkWest Hydrocarbon. Mr. Beatty began his career in the energy industry as in-house counsel for Colorado Interstate Gas Company, and ultimately became executive vice president, general counsel and director of The Coastal Corporation. He also served as chief of staff to Governor Roy Romer of Colorado. Mr. Beatty is a graduate of the Harvard Law School.

*Qualifications:* Through his experience as a director, officer and legal counsel of various energy companies, Mr. Beatty has extensive experience in the oil and gas industry, including significant experience in government energy policy and energy regulation. Mr. Beatty brings to our board his vast knowledge of the energy business, an acute awareness of current developments in the industry, as well as extensive historical knowledge of MarkWest.

*Other Public Company Directorships:* Denbury Resources Inc. (2007-2015); MarkWest Energy GP, L.L.C. (2008-2015)

*David A. Daberko.* David A. Daberko was elected a member of the board of directors of our general partner effective October 2012. Mr. Daberko serves on the boards of directors of MPC and RPM International, Inc. He joined National City Bank in 1968, and went on to hold a number of management positions with National City. In 1987, Mr. Daberko was elected deputy chairman of National City Corporation, a financial services corporation, now part of PNC Financial Services Group, Inc., and president of National City Bank in Cleveland. He served as president and chief operating officer from 1993 until 1995, when he was named chairman of the board and chief executive officer. He retired as chief executive officer in June 2007 and as chairman of the board in December 2007. Mr. Daberko holds a bachelor's degree from Denison University and a master's degree in business administration from Case Western Reserve University.

*Qualifications:* With nearly forty years of experience in the banking industry, including twelve years as the chairman and chief executive officer of a large financial services corporation, Mr. Daberko has extensive knowledge of the financial services and investment banking sectors. He also has considerable experience from his service as a member of other public company boards of directors, including within the energy industry. Mr. Daberko brings to our board his knowledge of public company financial reporting requirements and an understanding of the energy business.

*Other Public Company Directorships:* Marathon Petroleum Corporation (2011 to present); RPM International, Inc. (2007 to present); Williams Partners GP LLC (2010 to 2015)

*Timothy T. Griffith.* Timothy T. Griffith was elected a member of the board of directors of our general partner effective March 2015. Mr. Griffith is also senior vice president and chief financial officer of MPC. Prior to joining MPC in 2011, he served as vice president and treasurer of Smurfit-Stone Container Corporation, where he had executive responsibility for the company's investor interface and treasury operations, including capital structure, cash management, insurance and investment oversight. Mr. Griffith also served as vice president and treasurer of Cooper-Standard Automotive, as assistant treasurer of Lear Corporation, as the capital planning

officer for Comerica Incorporated and as a derivatives specialist with Citicorp Securities. He was vice president, Finance and Investor Relations, and treasurer of MPC and our general partner, and the vice president and chief financial officer of our general partner before assuming his current position in 2015. Mr. Griffith earned a bachelor's degree in economics from Michigan State University and a master's degree in business administration from the University of Michigan. He is also a chartered financial analyst, a designation he has held since 1995. He attended the Oxford Institute for Energy Studies in 2013.

*Qualifications:* Mr. Griffith has extensive experience and held a variety of roles in finance over the course of his career, dating from his first position in banking, his increasing responsibilities at several publicly traded and privately sponsored businesses, continuing through his roles managing the financial affairs of both MPC and our general partner, having served as the treasurer and chief financial officer of both entities. Mr. Griffith has been deeply involved in the Partnership's strategy formation and execution.

*Other Public Company Directorships:* None within the last five years

*Christopher A. Helms.* Christopher A. Helms was elected a member of the board of directors of our general partner effective October 2012. Mr. Helms is president and chief executive officer of US Shale Management Company, a wholly owned subsidiary of US Shale Energy Advisors LLC. He also serves on the board of directors of Range Resources Corporation. Mr. Helms is the co-founder of US Shale Energy Advisors LLC, a privately owned entity engaged in the development, ownership and operation of midstream energy assets. From 2005 until his retirement in 2011, Mr. Helms served in various capacities with NiSource Inc. and its affiliate, NiSource Gas Transmission and Storage, including as executive vice president and group chief executive officer. He was group president, pipeline of NiSource Inc. from 2005 to 2008, where he was also a member of the Executive Council and the Corporate Risk Management Committee. He served as chief executive officer and executive director of NiSource Gas Transmission and Storage from 2008 to 2011. At NiSource, Mr. Helms was responsible for leading the company's interstate gas transmission, storage and midstream businesses. Prior to his tenure at NiSource, Mr. Helms held senior executive positions with CMS Energy Corporation, and subsidiaries of Duke Energy Corporation and PanEnergy Corp. from 1990 to 2005. Mr. Helms graduated with a bachelor of arts degree from Southern Illinois University at Edwardsville and a juris doctor degree from the Tulane University School of Law.

*Qualifications:* As the chief executive officer of an energy midstream logistics company and a former senior executive with several vertically integrated natural gas companies, Mr. Helms has significant experience in the oil and natural gas businesses. His background includes overseeing joint ventures and mergers and acquisitions within the midstream energy sector. He draws upon his prior capacity supervising financial reporting functions in his role as one of our named audit committee financial experts. Through his service on other public company boards of directors, Mr. Helms has been exposed to a variety of management styles and governance approaches, and he serves as chair of our conflicts committee. He brings his considerable midstream energy expertise, particularly in operations and business combinations, and his skills in the areas of finance, accounting, compliance, strategic planning and risk oversight, to his service on our board.

*Other Public Company Directorships:* Range Resources Corporation (2014 to present); Questar Corporation (2013 to 2016)

*Garry L. Peiffer.* Garry L. Peiffer was elected a member of the board of directors of our general partner in June 2012. Mr. Peiffer retired as president of our general partner and as executive vice president, Corporate Planning and Investor & Government Relations of MPC in 2014. He is a member of the board of directors of the Fifth Third Bank (Northwestern Ohio). Mr. Peiffer is also a member of the boards of trustees of the Blanchard Valley Health System and the Findlay-Hancock County Community Foundation, and serves on the Blanchard Valley Port Authority Board. Mr. Peiffer began his career with Marathon Oil Company in 1974. During his career, he held a variety of management positions with increasing responsibilities. These responsibilities included supervisor of employee savings and retirement plans, controller of Speedway Petroleum Corporation and

numerous other marketing and logistics positions. In 1987, Mr. Peiffer was appointed to the President's Commission on Executive Exchange serving for a year in the Pentagon as special assistant to the Assistant Secretary of Defense for Production and Logistics. In 1988, he returned to Marathon Oil and was named vice president of Finance and Administration for Emro Marketing Company. He served as assistant controller, Refining, Marketing and Transportation beginning in 1992. Mr. Peiffer was named senior vice president of Finance and Commercial Services for Marathon Ashland Petroleum LLC in 1998, executive vice president of MPC in 2011 and president of our general partner in 2012. Mr. Peiffer graduated with a bachelor's degree in accounting from Bowling Green State University in 1974 and passed the certified public accountant exam in Ohio that same year.

*Qualifications:* As the retired president of our general partner and retired executive vice president, Corporate Planning and Investor & Government Relations of MPC, Mr. Peiffer has an extensive energy industry background. His significant career accomplishments include leading finance organizations, successfully realizing several joint ventures and corporate reorganizations and implementing new information technology solutions. As a recognized leader in the industry, Mr. Peiffer led the Partnership through the initial public offering process and in its first year of operations. He draws upon his prior capacity in various accounting and finance functions in his role as chair of the audit committee of our board and in serving as a named audit committee financial expert.

*Other Public Company Directorships:* None within the last five years

*Dan D. Sandman.* Dan D. Sandman was elected a member of the board of directors of our general partner effective October 2012. Mr. Sandman is an adjunct professor at The Ohio State University Moritz College of Law, where he has taught corporate governance law since 2007. He serves on the board of directors of CONSOL Coal Resources GP LLC, and has served on the board of directors of Roppe Corporation, a privately held company, since 1987. Additionally, Mr. Sandman serves on the boards of directors of the Carnegie Science Center, the Carnegie Hero Commission and Grove City College. He has served as a court-appointed mediator of commercial cases pending in U.S. federal courts and has lectured on corporate governance law at Oxford University. Mr. Sandman began his career with Marathon Oil Company in 1973 and served in a series of legal positions of increasing responsibility. In 1986, Mr. Sandman was appointed general counsel and secretary of Marathon, and in 1993 he was named general counsel and secretary of USX Corporation. Upon the spinoff of United States Steel Corporation from USX in 2002, Mr. Sandman was named vice chairman of the board of directors and chief legal and administrative officer of United States Steel, where he served until his retirement in 2007. During his time with United States Steel, Mr. Sandman was responsible at various times for management and oversight of aspects of Human Resources, Executive Compensation, Public Relations, Environmental and Government Affairs, as well as the Law Organization and the corporate secretary's office. Mr. Sandman graduated with a bachelor of arts degree from The Ohio State University in 1970 and a juris doctor degree from The Ohio State University College of Law in 1973. Mr. Sandman attended the Stanford Executive Program in 1989.

*Qualifications:* As the former vice chairman and chief legal officer of a large industrial firm, Mr. Sandman has considerable experience in legal and business affairs, transactional law, regulatory compliance and corporate governance, ethics and risk management matters that may arise in the context of the Partnership's business. He has also served as general counsel of a large integrated oil company and thus has an energy industry background. Mr. Sandman teaches corporate governance law as an adjunct professor and serves on the board of directors of a publicly held company and a private company, each engaged in manufacturing. Mr. Sandman brings to our board his valuable perspective, specifically on matters of strategic focus, governance and leadership.

*Other Public Company Directorships:* CONSOL Coal Resources GP LLC (2017 to present)

*Frank M. Semple.* Frank M. Semple was elected a member of the board of directors of our general partner effective December 4, 2015, at the time of the MarkWest Merger in fulfillment of our obligations under the merger agreement with MarkWest to appoint two directors identified by MarkWest to the board of our general

partner effective at the close of the merger. He also serves as a member of the board of directors of MPC. Mr. Semple was appointed vice chairman of our general partner effective at the close of the MarkWest Merger and served in that position until his retirement effective November 1, 2016. Prior to joining our general partner, Mr. Semple was the president and chief executive officer of MarkWest beginning on November 1, 2003, and was elected chairman of the board in 2008. Prior to joining MarkWest he completed a 22-year career with The Williams Companies, Inc. (“Williams”) and WilTel Communications. He served as the chief operating officer of WilTel Communications, senior vice president/general manager of Williams Natural Gas Company, vice president of operations and engineering for Northwest Pipeline Company and division manager for Williams Pipe Line Company. Prior to joining Williams, Mr. Semple served in the United States Navy. Mr. Semple earned a bachelor’s degree in mechanical engineering from the United States Naval Academy. He has completed the Program for Management Development at Harvard Business School.

*Qualifications:* As the former chairman and chief executive officer of MarkWest, Mr. Semple has proven leadership abilities in managing a complex business and a deep understanding of the midstream sector. Mr. Semple has significant experience regarding operations, strategic planning, finance and corporate governance matters.

*Other Public Company Directorships:* Marathon Petroleum Corporation (2015 to present); MarkWest Energy GP, L.L.C. (2003-2015)

*John P. Surma.* John P. Surma was elected a member of the board of directors of our general partner effective October 2012. Mr. Surma is a member of the boards of directors of MPC, Ingersoll-Rand plc and Concho Resources Inc. He is on the boards of directors of the National Safety Council and the University of Pittsburgh Medical Center. He formerly served as the chair of the board of directors of the Federal Reserve Bank of Cleveland. He was appointed by President Barack Obama to the President’s Advisory Committee for Trade Policy and Negotiations and served as its vice chairman. Mr. Surma retired as the chief executive officer of United States Steel Corporation, an integrated steel producer, in September 2013, and as executive chairman in December 2013. Prior to joining United States Steel, Mr. Surma served in several executive positions with Marathon Oil Corporation. He was named senior vice president, Finance & Accounting of Marathon Oil Company in 1997, president, Speedway SuperAmerica LLC in 1998, senior vice president, Supply and Transportation of Marathon Ashland Petroleum LLC in 2000 and president of Marathon Ashland Petroleum LLC in 2001. Prior to joining Marathon, Mr. Surma worked for Price Waterhouse LLP where he was admitted to the partnership in 1987. In 1983, Mr. Surma participated in the President’s Executive Exchange Program in Washington, D.C., where he served as executive staff assistant to the vice chairman of the Federal Reserve Board. Mr. Surma earned a bachelor of science degree in accounting from Pennsylvania State University in 1976.

*Qualifications:* As the retired chairman and chief executive officer of a large industrial firm, Mr. Surma has a broad range of experiences that shape his viewpoint on the strategic direction and operations of the Partnership. Mr. Surma brings to the board his significant experience in public accounting and in executive leadership in the energy and steel industries. His service on other public company boards of directors also affords him a perspective that is particularly valuable to our board.

*Other Public Company Directorships:* Marathon Petroleum Corporation (2011 to present); Concho Resources Inc. (2014 to present); Ingersoll-Rand plc (2012 to present); United States Steel Corporation (2001 to 2013)

*Donald C. Templin.* Donald C. Templin was elected a member of the board of directors of our general partner in June 2012. He is president of MPC. He is a member of the board of directors of Calgon Carbon Corporation. Mr. Templin is chairman of the Downstream Committee of API. Prior to joining MPC in 2011, Mr. Templin was the managing partner of the audit practice for PricewaterhouseCoopers LLP (“PwC”) in Georgia, Alabama and Tennessee. While at PwC, he completed more than 25 years of providing auditing and advisory services to a wide variety of private, public and multinational companies. Mr. Templin joined PwC in Pittsburgh in 1984. While at PwC, he went on to serve in London, Kazakhstan and Baltimore before assuming his position in Atlanta

in 2009. Mr. Templin was appointed senior vice president and chief financial officer of MPC in 2011, vice president and chief financial officer of our general partner in 2012, executive vice president, supply, transportation and marketing of MPC in 2015, president of our general partner and executive vice president of MPC in 2016, and assumed his current position in 2017. Mr. Templin is a graduate of Grove City College, a certified public accountant and a member of the American Institute of Certified Public Accountants. He attended the Oxford Institute for Energy Studies in 2012.

*Qualifications:* As the current president of MPC, along with his prior positions with both MPC and our general partner, Mr. Templin has direct insight into all aspects of our business, from an operational and commercial perspective, and in the areas of accounting, audit and financial management. Mr. Templin also has a long and successful background in public accounting for energy sector clients and draws from that experience on matters relating to public company financial reporting requirements. Mr. Templin serves on one outside public company board of directors, which provides him exposure to perspectives on management and governance that may differ from those of our general partner. Mr. Templin brings his extensive energy industry background, particularly his expertise in accounting, financial reporting and strategic planning, to his service on our board.

*Other Public Company Directorships:* Calgon Carbon Corporation (2013 to present)

*Gregory S. Floerke.* Gregory S. Floerke is executive vice president, Gathering and Processing of our general partner. He joined our general partner in December 2015, at the time of the MarkWest Merger and was named executive vice president and chief commercial officer, MarkWest assets. He was named executive vice president and chief operating officer, MarkWest operations in 2016 and assumed his current position in 2018. Prior to joining our general partner, Mr. Floerke was executive vice president and chief commercial officer at MarkWest beginning in 2015 and senior vice president, Northeast region at MarkWest beginning in 2013. Previously, Mr. Floerke held senior management positions at Access Midstream Partners, L.P. from 2011 until 2013, and One Communications Corp. from 2007 until 2011.

*John S. Swearingen.* John S. Swearingen is executive vice president, Logistics and Storage of our general partner. He was previously vice president, crude oil and refined products pipelines and chief operating officer of pipeline operations of our general partner and senior vice president, Transportation and Logistics of MPC from 2015 until he was appointed executive vice president, Transportation and Logistics of our general partner in 2017. He was appointed to his current position in 2018. Prior to that, Mr. Swearingen was vice president and chief operating officer since 2014. Previously, Mr. Swearingen served in various leadership positions, including as vice president, Health, Environment, Safety and Security beginning in 2011 and president of Marathon Pipeline LLC beginning in 2009.

*Raymond L. Brooks.* Raymond L. Brooks is senior vice president of our general partner and senior vice president, Refining of MPC. He was appointed to his current position with our general partner effective February 1, 2018, and has served in his position with MPC since March 1, 2016. Prior to these appointments, Mr. Brooks was general manager, Galveston Bay refinery of MPC beginning in February 2013, general manager, Robinson refinery of MPC beginning in 2010 and general manager, St. Paul Park, Minnesota refinery (no longer owned by MPC) beginning in 2006.

*Thomas M. Kelley.* Thomas M. Kelley is senior vice president of our general partner and senior vice president, Marketing of MPC. He was appointed to his current position with our general partner effective February 1, 2018, and has served in his position with MPC since June 30, 2011. Prior to these appointments, Mr. Kelley served as senior vice president, Marketing for Marathon Petroleum Company LP beginning in January 2010.

*C. Michael Palmer.* C. Michael Palmer is senior vice president of our general partner and senior vice president, Supply Distribution and Planning of MPC. He was appointed to his current position with our general partner effective February 1, 2018, and has served in his position with MPC since June 30, 2011. Prior to these appointments, Mr. Palmer served as vice president, Crude, Supply and Logistics of Marathon Petroleum Company LP beginning in June 2010.

*Timothy J. Aydt.* Timothy J. Aydt is vice president, operations of our general partner and president of Marathon Pipe Line. He was appointed to his current positions effective January 1, 2017. Prior to these appointments, Mr. Aydt served as the Terminal, Transport and Rail general manager of MPC beginning in 2013, and the project director for the Detroit Heavy Oil Upgrade Project beginning in 2008.

*Molly R. Benson.* Molly R. Benson is vice president, corporate secretary and chief compliance officer of our general partner and of MPC. She was appointed to her current position effective March 1, 2016. Prior to this appointment, Ms. Benson was assistant general counsel, Corporate and Finance of MPC beginning in April 2012, and group counsel, Corporate and Finance of MPC beginning in 2011.

*Suzanne Gagle.* Suzanne Gagle is vice president and general counsel of our general partner and of MPC. She was appointed to her current position with our general partner effective October 1, 2017, and has served in her position with MPC since March 1, 2016. Prior to these appointments, Ms. Gagle was assistant general counsel, litigation and Human Resources beginning in April 2011, senior group counsel, downstream operations beginning in 2010 and group counsel, litigation, beginning in 2003.

*Peter Gilgen.* Peter Gilgen is vice president and treasurer of our general partner. He was appointed to his current position effective February 1, 2017. Prior to this appointment, Mr. Gilgen was assistant treasurer of MPC beginning in 2012, and Corporate Finance and Banking manager beginning in 2011.

*C. Kristopher Hagedorn.* C. Kristopher Hagedorn is vice president and controller of our general partner. He joined our general partner in 2017. Prior to joining our general partner, Mr. Hagedorn was vice president and controller at CONSOL Energy Inc. beginning in 2015, assistant controller beginning in 2014 and director, financial accounting beginning in 2012. He served as chief accounting officer for CONE Midstream Partners LP from 2014 to 2015. Previously, Mr. Hagedorn served in positions of increasing responsibility with PricewaterhouseCoopers beginning in 1998.

## **GOVERNANCE PRINCIPLES**

Our governance principles are available on our website at <http://ir.mplx.com> by selecting “Corporate Governance” and clicking on “Governance Principles.” In summary, our Governance Principles provide the functional framework of the board of directors of our general partner, including its roles and responsibilities. These principles also address board independence, committee composition, the process for director selection and director qualifications, the board’s performance review, the board’s planning and oversight functions, director compensation and director retirement and resignation.

## **LEADERSHIP STRUCTURE OF THE BOARD**

As provided in our governance principles, our board of directors does not have a policy requiring the roles of chairman of the board and chief executive officer to be filled by separate persons or requiring the chairman of the board to be a non-management director. Mr. Heminger, our general partner’s chief executive officer, serves as chairman of the board. Our board has determined that due to his extensive knowledge of all aspects of the Partnership’s business, as well as the continued relationship between the Partnership and MPC, Mr. Heminger is in the best position to lead the board as its chairman.

Our governance principles also provide that when the role of chairman of the board is filled by the chief executive officer, the board may appoint an independent director as a “lead director” to preside over executive sessions of the board or other board meetings when the chairman is absent. Dan D. Sandman, an independent director, serves as the “lead director” of the board of directors of our general partner.

The leadership structure of our board, with the combined role of chairman and chief executive officer and the independent oversight promoted by our lead director, offers a balanced approach that our board believes serves the Partnership well at this time.



## **COMMUNICATIONS FROM INTERESTED PARTIES**

All interested parties may communicate directly with our independent directors by submitting a communication in an envelope addressed to the “Board of Directors (non-management members)” in care of the corporate secretary of our general partner, MPLX GP LLC, 200 East Hardin Street, Findlay, Ohio 45840. Additionally, interested parties may communicate with our audit and conflicts committee chairs and the independent directors, individually or as a group, by sending an e-mail to the following e-mail addresses:

Audit Committee Chair	auditchair@mplx.com
Conflicts Committee Chair	conflictschair@mplx.com
Independent Directors	non-managedirectors@mplx.com

The corporate secretary of our general partner will forward to the directors all communications that, in the corporate secretary’s judgment, are appropriate for consideration by the directors. Examples of communications that would not be considered appropriate include commercial solicitations.

## **BENEFICIAL OWNERSHIP REPORTING COMPLIANCE**

Section 16(a) of the Exchange Act, as amended, requires the directors and executive officers of our general partner and persons who own more than 10 percent of a registered class of our equity securities, to file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Forms 4 or 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us from the persons required to file reports, we believe that each of the directors and executive officers of our general partner and persons who own more than 10 percent of a registered class of our equity securities has complied with the applicable reporting requirements for transactions in our equity securities during the fiscal year ended December 31, 2017.

## **CODE OF BUSINESS CONDUCT**

Our code of business conduct is available on our website at <http://ir.mplx.com> by selecting “Corporate Governance” and clicking on “Code of Business Conduct.”

## **CODE OF ETHICS FOR SENIOR FINANCIAL OFFICERS**

Our code of ethics for senior financial officers is available on the Partnership’s website at <http://ir.mplx.com> by selecting “Corporate Governance” and clicking on “Code of Ethics for Senior Financial Officers.” This code of ethics applies to our chairman of the board of directors and chief executive officer, chief financial officer, chief accounting officer, controller and treasurer and other persons performing similar functions, as well as to those designated as senior financial officers by our chairman and chief executive officer or our audit committee.

Under this code of ethics, these senior financial officers shall, among other things:

- act with honesty and integrity, including the ethical handling of actual or apparent conflicts of interest between personal and professional relationships;
- provide full, fair, accurate, timely and understandable disclosure in reports and documents filed with, or submitted to, the SEC, and in other public communications;
- comply with applicable laws, governmental rules and regulations, including insider trading laws; and
- promote the prompt internal reporting of potential violations or other concerns related to this code of ethics to the chair of the audit committee and to the appropriate person or persons identified in the code of business conduct.

## **COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION**

The chairman and the independent directors of our board review compensation related matters for our general partner. During 2017, none of our general partner’s executive officers served as a member of a compensation

committee or board of directors of any unaffiliated entity that has an executive officer serving as an independent director on our board. Gary R. Heminger serves as an officer and director of our general partner and MPC.

### **Item 11. Executive Compensation**

#### **COMPENSATION COMMITTEE REPORT**

The chairman of the board and independent directors of our general partner (for purposes of this report and certain disclosures made within the following Compensation Discussion and Analysis, the “Committee”) have reviewed and discussed MPLX LP’s Compensation Discussion and Analysis for 2017 with MPLX LP’s management. Based on its review and discussions, the Committee has recommended to the board of directors of our general partner that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Gary R. Heminger, Chairman  
Michael L. Beatty  
David A. Daberko  
Christopher A. Helms  
Garry L. Peiffer  
Dan D. Sandman  
John P. Surma

## COMPENSATION DISCUSSION AND ANALYSIS

In this section, we describe the material components of our general partner’s executive compensation program for our named executive officers (“NEOs”) and we explain how and why 2017 compensation decisions were made. We recommend that this compensation discussion and analysis be read in conjunction with the tabular and narrative disclosures in the “Executive Compensation” section of this Annual Report on Form 10-K.

### Named Executive Officer Compensation

Our NEOs consist of the principal executive officer (“PEO”), principal financial officer (“PFO”), and the executive officers of our general partner as of December 31, 2017, listed below. The names and titles of our six NEOs as of that date were as follows:

<u>Name</u>	<u>Title (as of December 31, 2017)</u>
Gary R. Heminger	Chairman of the Board and Chief Executive Officer
Pamela K.M. Beall	Executive Vice President and Chief Financial Officer
Michael J. Hennigan	President
C. Corwin Bromley	Executive Vice President
Gregory S. Floerke	Executive Vice President, MarkWest Operations
Donald C. Templin	Former President, MPLX

Mr. Hennigan was appointed MPLX President on June 20, 2017, succeeding Mr. Templin who was appointed MPC President effective July 1, 2017.

Mr. Bromley retired effective January 1, 2018.

### Overview

We do not directly employ any of the personnel responsible for managing and operating our business. Instead, we contract with MPC to provide the necessary personnel, all of whom are directly employed by MPC or one of its affiliates. As consideration for MPC’s and its affiliates’ provision of these services, we pay MPC a fixed amount that reflects the cost incurred by MPC and its affiliates in providing the services of our executive officers, in accordance with the terms of the omnibus agreement.

Mr. Heminger generally devotes less than a majority of his total business time to our general partner and us and receives compensation from MPC that is not intended as remuneration for the services he provides to our business (including the business of our general partner). With respect to the services he provides to our business, we reimburse MPC for the fixed fee amount in accordance with the terms of the omnibus agreement. Mr. Heminger’s fixed fee and his long-term incentive grants made by our general partner, which represent all of the material elements of his compensation attributable to the services he provides to our business, are disclosed in this compensation discussion and analysis. In 2017, Ms. Beall and Messrs. Hennigan, Bromley and Floerke devoted substantially all of their total business time to our business; accordingly, all of the material elements of their compensation are disclosed in this compensation discussion and analysis. Mr. Templin devoted 90 percent of his total business time during his tenure as MPLX President to our business; thus, the material elements of his compensation for the services he provides to our business are discussed below, subject to appropriate proration.

Our general partner has adopted the MPLX 2012 Plan for the benefit of eligible officers, employees, and directors of our general partner and its affiliates, including MPC, who provide services to our business. Any award under the MPLX 2012 Plan for our NEOs must be first recommended by the compensation committee of the board of directors of MPC (the “MPC Compensation Committee”). If a recommendation is made, an award will be granted to one of our NEOs only if it is approved by the board of directors of our general partner, which is typically done on an annual basis.

Except with respect to awards that may be granted under our MPLX 2012 Plan, all responsibility and authority for compensation-related decisions for our NEOs remain with the MPC Compensation Committee, currently comprised of five independent directors, and are not subject to any approval by us, the board of directors of our general partner or any committees thereof. Other than awards granted under the MPLX 2012 Plan, MPC has the ultimate decision-making authority with respect to the total compensation of its and its subsidiaries' executive officers and employees. The fixed amount charged to us for the services of our NEOs is provided for in the omnibus agreement as previously described in this Annual Report on Form 10-K.

All final determinations with respect to awards under the MPLX 2012 Plan will be made by the board of directors of our general partner or any committee thereof that may be established for such purpose.

### Compensation Consultants

Our general partner does not have a standing compensation committee, and its board of directors has not hired its own compensation consultant. Pay Governance, LLC ("Pay Governance") has been engaged to provide compensation consulting services and benchmarking information to the MPC Compensation Committee. The advice Pay Governance provides to the MPC Compensation Committee is typically shared with the board of directors of our general partner for use in making certain compensation decisions with respect to our NEOs.

### Compensation of Our New President

Concurrent with the announcement of the appointment of Mr. Templin, MPLX's former president, to his new role as President of MPC, MPLX announced that the board of directors of our general partner appointed Mr. Hennigan to succeed Mr. Templin as President of our general partner effective June 20, 2017. Mr. Hennigan's annual base salary is \$800,000 with an annual bonus target of 100 percent of his base salary. Mr. Hennigan received a \$1,000,000 cash sign-on bonus.

Mr. Hennigan also received grants of MPLX phantom units with an intended value of \$1,600,000 and MPC restricted stock with an intended value of \$400,000, which were granted as part of Mr. Hennigan's regular annual compensation and in lieu of regular annual long-term incentive grants, which had been made to other NEOs earlier in the year. These units/shares will vest in three equal installments on the first, second and third anniversaries of the date of grant. In addition, Mr. Hennigan received special, one-time grants of MPLX phantom units with an intended value of \$2,400,000 and MPC restricted stock with an intended value of \$600,000, both of which will fully vest in one installment on the third anniversary of the grant date. These equity awards were intended to partially replace the outstanding equity Mr. Hennigan forfeited upon termination with his former employer.

Mr. Hennigan participates in the same executive officer compensation programs and benefit plans as other NEOs. He does not have an employment agreement.

## ELEMENTS OF COMPENSATION

### Base Compensation

Our NEOs earn a base salary for their services to MPC and to us, which is paid by MPC or its affiliates. We incur only a fixed expense per month with respect to the compensation paid to each of our NEOs, as provided for in the omnibus agreement. As of December 31, 2017, we incurred the annualized fixed fee for Mr. Heminger of \$1,310,000. The MPC Compensation Committee made the following base salary adjustments in 2017, which were paid by MPC:

Name	Title	Previous Base Salary (\$)	Base Salary Effective Dec. 31, 2017 (\$) <sup>(1)</sup>	Increase (%)
Gregory S. Floerke	Executive Vice President, MarkWest Operations	420,000	450,000	7.1
Donald C. Templin	Former President, MPLX	720,000	742,500	3.1

- (1) The amount for Mr. Templin represents his base salary on June 20, 2017, when his tenure as MPLX President ended.

The increases for Messrs. Floerke and Templin reflect an adjustment to bring the base salary for each closer to the market median for his position. Annual base salary adjustments are made on April 1 of each year. As Mr. Hennigan was not employed on that date, he was not eligible for an increase. Ms. Beall's and Mr. Bromley's base salaries were deemed to be market competitive and therefore did not receive an adjustment.

### Annual Cash Bonus Payments

Ms. Beall and Messrs. Hennigan, Bromley, Floerke and Templin were eligible to earn an annual bonus payment under MPC's Annual Cash Bonus ("ACB") program for the services they provide to our business. Any bonus payment made to our NEOs will be determined solely by MPC without input from us or the board of directors of our general partner. Under the provisions of the omnibus agreement, no portion of any bonus paid by MPC to our NEOs will be charged back to us. The ACB program is a variable incentive program intended to motivate and reward NEOs for achieving short-term (annual) financial and operational business objectives that drive overall shareholder value while encouraging responsible risk-taking and accountability. The majority (70 percent) of the ACB is determined by pre-established financial and operational (including environmental and safety) performance measures and the remaining 30 percent is driven by a number of discretionary factors, including adjustments due to the volatility in petroleum-related commodity prices throughout the year, which makes it difficult to establish reliable, pre-determined goals.

The financial and operational performance metrics used for the 2017 ACB program were:

Performance Metric	Description	Type of Measure
Operating Income Per Barrel <sup>(1)</sup>	Measures domestic operating income per barrel of crude oil throughput, adjusted for unusual business items and accounting changes. This metric compares a group of nine integrated or downstream companies, including MPC.	Financial (relative)
EBITDA <sup>(2)</sup>	As derived from MPC's consolidated financial statements and adjusted for certain items.	Financial (absolute)
Mechanical Availability <sup>(3)</sup>	Measures the mechanical availability and reliability of MPC's and MPLX's operated Refining and Marketing and Midstream segment operations.	Operational (absolute)
Selling, General and Administrative Costs (SG&A) <sup>(4)</sup>	MPC's actual selling, general and administrative expenses adjusted for certain items.	Financial (absolute)
Distributable Cash Flow (DCF) Attributable to MPLX <sup>(5)(6)</sup>	As derived from MPLX's consolidated financial statements and disclosed to investors as part of the quarterly earnings materials.	Financial (absolute)
Asset Dropdown Readiness and Execution <sup>(6)</sup>	Actual readiness and execution of dropping assets and services generating a specified amount of EBITDA to MPLX.	Financial (absolute)

Performance Metric	Description	Type of Measure
Responsible Care <sup>(7)</sup>	The metrics below measure MPC's success in meeting its goals for the health and safety of its employees, contractors and neighboring communities, while continuously improving on its environmental stewardship commitment by minimizing its environmental impact.	
Marathon Safety Performance Index <sup>(8)</sup>	Measurement of MPC's success and commitment to employee safety. Goals are set annually at best-in-class industry performance, focusing on continual improvement. This includes common industry metrics such as Occupational Safety and Health Administration (or OSHA) Recordable Incident Rates and Days Away Rates.	Operational (absolute)
Process Safety Events Rate	Measures the success of MPC's ability to identify, understand and control process hazards, which can be defined as unplanned or uncontrolled releases of highly hazardous chemicals or materials that have the potential to cause catastrophic fires, explosions, injury, plant damage and high-potential near misses or toxic exposures.	Operational (absolute)
Designated Environmental Incidents	Measures environmental performance and consists of tracking certain: a) releases of hazardous substances into air, water or land; b) permit exceedances; and c) government agency enforcement actions.	Operational (absolute)
Quality	Measures the impact of product quality incidents and cumulative costs to MPC (no Category 4 Incident, and costs of Category 3 Incidents). <sup>(9)</sup>	Operational (absolute)

(1) This is a per barrel measure of throughput—U.S. downstream segment income adjusted for certain items. It includes a total of nine comparator companies (including MPC). Comparator company income is adjusted for special items or other like items as adjusted by MPC. The comparator companies for 2017 were: Andeavor; BP p.l.c.; Chevron Corporation; ExxonMobil Corporation; HollyFrontier Corporation; PBF Energy; Phillips 66; and Valero Energy Corporation. This is a non-GAAP performance metric which is calculated as income before taxes, as presented in MPC's audited consolidated financial statements, as adjusted, divided by the total number of barrels of crude oil throughput at the peer's respective U.S. refinery operations. To ensure consistency of this metric when comparing results to the comparator group, adjustments to MPC's and peer company segment income before taxes are sometimes necessary to remove certain items such as the gain/loss on asset sales and certain asset and goodwill impairment expenses.

(2) This is a non-GAAP performance metric. It is calculated as MPC's earnings before interest and financing costs, interest income, income taxes, depreciation and amortization expense adjusted to exclude the effects of impairment expense, pension settlement expense, inventory market valuation adjustments, EBITDA related to acquisitions and divestitures and certain other non-cash adjustments.

- (3) Mechanical availability represents the percentage of capacity available for critical downstream and midstream equipment to perform its primary function for the full year.
- (4) This represents SG&A expenses per MPC's consolidated financial statements adjusted to exclude costs related to employee bonus program accruals, pension settlement expense, credit card processing fees, allocations of employee benefit expenses, inter-department cost allocations and expenses related to acquisitions and divestitures.
- (5) This is a non-GAAP performance metric. A reconciliation to the nearest GAAP financial measure is included in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information.
- (6) Subject to limitations imposed by Section 162(m) of the Code, the Company reserved the right to recalibrate the performance levels if significant tax reform suggested a portion of the dropdowns should be delayed into 2018.
- (7) Excludes Speedway.
- (8) This metric measures the personal safety performance level of MPC employees and contractors based on lost time, the number of OSHA recordable injuries or fatalities, and restricted duty incidents. In the event of a fatality, payout is determined by the MPC Compensation Committee.
- (9) A Category 4 Incident is one that involves a fatality. Category 3 Incidents include those in which: we incur out-of-pocket costs for incident response and recovery activities, mitigation of customer claims or regulatory penalties in excess of \$100,000; a media advisory is issued by MPC; or the extenuating circumstances are deemed to be of such severity by MPC's Quality Committee that a recommendation for this category is made to the MPC Quality Steering Committee and is subsequently approved. Quality incidents exclude MarkWest assets. Category 3 Incidents exclude assets acquired in 2017; Category 4 Incidents include assets acquired in 2017.

The threshold, target and maximum levels of performance for each performance metric were established for 2017 by evaluating factors such as performance achieved in the prior year(s), anticipated challenges for 2017, MPC's business plan and overall strategy. At the time the performance levels were set for 2017, the threshold levels were viewed as likely achievable, the target levels were viewed as challenging but achievable, and the maximum levels were viewed as extremely difficult to achieve.

The table below provides both the goals for each metric and MPC's performance achieved in 2017:

Performance Metric	Threshold Level 50% Payout	Target Level 100% Payout	Maximum Level 200% Payout	Performance Metric Result	Target Weighting	Performance Achieved
Operating Income Per Barrel	5 <sup>th</sup> or 6 <sup>th</sup> Position	3 <sup>rd</sup> or 4 <sup>th</sup> Position	1 <sup>st</sup> or 2 <sup>nd</sup> Position	2 <sup>nd</sup> Position (200% of target)	15.0%	30.0%
EBITDA <sup>(1)</sup>	\$ 3,500	\$ 5,800	\$ 6,500	\$6,026 (132% of target)	10.0%	13.2%
Mechanical Availability	93.5%	94.5%	95.5%	95.7% (200% of target)	10.0%	20.0%
Selling, General and Administrative Costs <sup>(1)</sup>	\$ 1,915	\$ 1,875	\$ 1,845	\$1,839 (200% of target)	5.0%	10.0%
Distributable Cash Flow Attributable to MPLX LP <sup>(1)</sup>	\$ 1,200	\$ 1,400	\$ 1,450	\$1,628 (200% of target)	5.0%	10.0%
Asset Dropdown Readiness and Execution	See Footnote for Performance Target Breakdown <sup>(2)</sup>			Maximum (200% of target)	5.0%	10.0%
Responsible Care Marathon Safety Performance Index	1.00	0.65	0.40	0.95 (57% of target)	5.0%	2.9%
Process Safety Events Rate	0.58	0.39	0.31	0.31 (200% of target)	5.0%	10.0%
Designated Environmental Incidents	72	51	30	31 (200% of target)	5.0%	10.0%
Quality	\$500,000	\$250,000	\$125,000	\$0 (200% of target)	5.0%	10.0%
				<b>Total</b>	<b>70.0%</b>	<b>126.1%</b>

(1) Represented in millions.

(2) Threshold: Complete readiness for dropping an estimated \$800 million of EBITDA generating assets into MPLX by December 31, 2017.

Target: Complete Threshold level and execute drops totaling an estimated \$600 million in EBITDA generating assets into MPLX by December 31, 2017.

Maximum: Complete Threshold level and execute drops totaling an estimated \$800 million in EBITDA generating assets into MPLX by December 31, 2017.

The MPC Compensation Committee determined Maximum performance was achieved as definitive agreements for the contribution of \$1.4 billion in EBITDA-generating assets and services were executed in 2017 with closing for a portion deferred until the first quarter of 2018 due to tax reform.



*Organizational and Individual Performance Achievements for the 2017 ACB Program*

At the beginning of the year, each NEO develops individual performance goals relative to their respective organizational responsibilities, which are directly related to MPC's business objectives. The subjective goals used to evaluate the individual performance of our NEOs for 2017 fell into the following general categories:

	<u>Mr. Hennigan</u>	<u>Ms. Beall</u>	<u>Mr. Floerke</u>	<u>Mr. Bromley</u>	<u>Mr. Templin</u>
Talent development, retention, succession and acquisition	✓	✓	✓	✓	✓
Enhancement of unitholder value through return of capital and unlocking midstream asset value	✓	✓	✓		✓
System integration, optimization and debottlenecking	✓		✓		✓
Growth through organic expansion and acquisition opportunities	✓	✓	✓	✓	✓
Preparation of MPC assets for potential dropdown to MPLX LP	✓	✓	✓	✓	✓
Progress on diversity initiatives	✓	✓	✓	✓	✓

MPC's Chairman and CEO reviews the organizational and individual performance of our NEOs and makes annual bonus recommendations to the MPC Compensation Committee. Key factors considered for 2017 included:

- Completed strategic initiatives announced by MPC and MPLX in early 2017, including the dropdown to MPLX of assets generating MLP-qualifying EBITDA and executed the exchange of MPC's economic general partner interest in MPLX, including its incentive distribution rights (or IDRs), for a non-economic general partner interest and MPLX LP common units.
- MPC's net income attributable to MPC increased to \$3.43 billion, or \$6.70 per diluted share, in 2017 from \$1.17 billion, or \$2.21 per diluted share, in 2016. Earnings in 2017 include a tax benefit of approximately \$1.5 billion (or \$2.93 per diluted share) related to tax reform legislation enacted in the fourth quarter of 2017.
- MPC increased its quarterly dividend by 11 percent to \$0.40 per share from \$0.36 per share in 2017, and again increased the dividend by 15 percent to \$0.46 per share in the first quarter of this year, representing a 26.5 percent compound annual growth rate from the dividend established when it became an independent company on June 30, 2011.
- MPC continued to focus on returning capital to shareholders returning \$3.1 billion to shareholders through dividends and share repurchases.
- MPC Total Shareholder Return ("TSR") for 2017 was 34.6 percent compared with median TSR of 26.7 percent for its performance unit peer group.
- MPLX Total Unitholder Return ("TUR") for 2017 was 17.5 percent compared with median TUR of 0.4 percent for its performance unit peer group.
- MPLX reported record financial results on record volume growth across the gathering and processing business. MPLX delivered on its 12.1 percent distribution growth guidance for 2017 distributions and has increased its quarterly cash distribution for 20 consecutive quarters, representing an 18.3 percent compound annual growth rate over the minimum quarterly distribution established at its formation in late 2012.

Bonus opportunities for our NEOs under the ACB program are communicated as a target percentage of annualized base salary at year end. Each of our NEOs can generally earn a maximum of 200 percent of the target award, or earn no award at all, depending on MPC and MPLX's overall performance and the subjective

evaluation of each NEO's organizational and individual performance. The MPC Compensation Committee reviews market data provided by its compensation consultant annually with respect to competitive pay levels and annually approves specific bonus target opportunities for each of our NEOs. MPC does not guarantee minimum bonus payments to any of our NEOs.

### 2018 Bonus Payments (for 2017 Performance)

In February 2018, the MPC Compensation Committee certified the results of the performance metrics for the 2017 ACB program and applied the following formula based on performance of established metrics, as well as organizational and individual performance, to determine our NEOs' final award for 2017 performance:

	Annualized Base Salary (as of 12/31/17)	X	Bonus Target (as a percent of base salary)	X	Final Award Percent (as a percent of target)	=	Final Award	
Name <sup>(1)</sup>	Annualized Base Salary (as of 12/31/17) (\$) <sup>(2)</sup>		Bonus Target as a % of Base Salary (%)		Target Bonus (\$)		Final Award as a % of Target (%)	Final Award (\$) <sup>(3)</sup>
Pamela K.M. Beall	525,000		70		367,500		182.1	670,000
Michael J. Hennigan	429,589		100		429,589		186.0	800,000
C. Corwin Bromley	465,000		60		279,000		—	—
Gregory S. Floerke	450,000		70		315,000		190.5	600,000
Donald C. Templin	405,000		100		405,000		188.9	765,000

- (1) Mr. Heminger is not included as he generally devotes less than a majority of his total business time to our general partner and us.
- (2) Mr. Hennigan's salary reflects his base pay earnings from his hire date on June 19, 2017 through December 31, 2017. Mr. Templin's salary reflects his year-end salary adjusted for his allocation of 90 percent to our general partner and pro-rated to reflect his tenure as MPLX President, which ended June 20, 2017.
- (3) The final award is rounded to the nearest \$5,000.

### MPLX Long-Term Incentive Compensation Program

In January 2017, the board of directors of our general partner met and approved a long-term incentive (or "LTI") design whereby annual LTI awards granted to our NEOs were in the form of performance units (50 percent) and phantom units (50 percent). Each form of LTI generally rewards performance over a multi-year period to the extent service (for phantom units) or partnership performance metrics (for performance units) are achieved. The primary purpose of LTI grants to our NEOs is to advance our long-term business objectives and strengthen the alignment between the interests of our executive officers and our unitholders. The forms of LTI awards differ as illustrated below:

Form of LTI Award	Form of Settlement	Compensation Realized
MPLX Performance Units	25 percent in MPLX LP common units and 75 percent in cash	\$0.00 to \$2.00 per unit based on our relative Total Unitholder Return (or "TUR") ranking among a group of peers, and a DCF metric for awards granted in 2017 and 2018
MPLX Phantom Units	MPLX LP common units	Value of common units upon vesting

Due to the nature of LTI awards, the actual long-term compensation value realized by our NEOs will depend on the price of the underlying unit at the time of settlement. The 2017 LTI awards were based on an intended dollar value rather than a specific number of performance units or phantom units.

#### *Performance Units*

The board of directors of our general partner believes that performance unit awards complement our phantom unit program. In 2017, the board of directors of our general partner, after reviewing performance programs of our peer companies, added a second performance metric to our performance unit program to align it with contemporary industry program design. In addition to the existing metric of TUR relative to a peer group of midstream competitors, a DCF-per-MPLX-LP-common-unit metric was added. The DCF-per-MPLX-LP-common-unit metric was chosen as unitholders also place significant importance on DCF to measure an MLP's performance relative to others within the same industry. The board of directors of our general partner believes the combination of these two metrics will better align the pay of our NEOs with the value delivered to our unitholders. Achieving above target payouts from our performance unit program will require at least one of these two metrics to achieve above target performance. This second metric was added to all performance unit grants starting in 2017.

Each performance unit is dollar denominated with a target value of \$1.00. The actual payout will vary from \$0.00 to \$2.00 (zero percent to 200 percent of target.). The board of directors of our general partner believes that having the maximum payout capped at \$2.00 per unit mitigates excessive or inappropriate risk-taking. The final value of the 2015 and 2016 performance unit awards will continue to be determined based solely on the results of MPLX's TUR. The final value of the 2017 performance unit awards will be based 50 percent on the results of MPLX's TUR and 50 percent on the results of the DCF-per-MPLX-LP-common-unit metric. These awards settle 25 percent in MPLX LP common units and 75 percent in cash.

#### Total Unitholder Return

Under the MPLX program, TUR for MPLX and that of each of the peer group MLPs is measured over a 36-month performance cycle. Each performance cycle has four equally weighted measurement periods: (1) the first 12 months, (2) the second 12 months, (3) the third 12 months and (4) the entire 36-month period. The board of directors of our general partner believes that measuring TUR over four measurement periods in the 36-month performance cycle is appropriate and serves the best interests of our unitholders. By having four equally weighted measurement periods, attaining maximum payout based on TUR may be achieved only by outperforming the TUR of the peer group for all four measurement periods.

Each peer group member's TUR is determined by taking the sum of the unit price appreciation or reduction, plus its cumulative cash distributions, for each measurement period and dividing that total by the peer group member's beginning unit price for that period, as shown below.

$$\frac{(\text{Ending Unit Price} - \text{Beginning Unit Price}) + \text{Cumulative Cash Distributions}}{\text{Beginning Unit Price}}$$

The beginning and ending unit prices for MPLX and each peer group member in the TUR calculation are the average of the MLP's respective closing unit prices for the 20 trading days immediately preceding the beginning or ending date of the applicable measurement period. This design mitigates significant market fluctuations in the unit price at the beginning or end of a performance cycle and discourages excessive or inappropriate risk-taking near the end of a performance cycle by limiting the impact on the overall payout of the award.

MPLX LP's TUR performance percentile within the peer group is measured for each measurement period with the related payout percentage determined using the following table. However, if MPLX LP's TUR is negative for a measurement period, the TUR payout percentage for that measurement period is capped at target (100 percent) regardless of actual relative TUR performance percentile. We refer to this provision as a "negative TSR cap".

TUR Percentile	Payout Percentage (% of Target)*
100 <sup>th</sup> (Highest)	200%
50 <sup>th</sup>	100%
25 <sup>th</sup>	50%
Below 25 <sup>th</sup>	0%

\* Payout for performance between quartiles will be determined using linear interpolation.

#### Distributable Cash Flow per MPLX LP Common Unit

The DCF-per-MPLX-LP-common-unit metric used for 2017 performance unit awards measures the growth of MPLX's full-year DCF over the three-year performance cycle. Payout for the DCF metric will be based on achievement of DCF in the last year of the performance cycle as compared with the threshold, target and maximum levels, which will be calculated by applying pre-determined compounded annual growth rates ("CAGR") against the DCF of the year prior to the beginning of the 36-month performance cycle.

#### ***MPLX Performance Units Granted in 2015***

Performance units granted in 2015 had a performance cycle of January 1, 2015, through December 31, 2017 and use TUR as the sole performance metric. Additional information about these grants, including the peer group used, can be found in the "Long-Term Incentive Compensation" section of our Annual Report on Form 10-K for the year ended December 31, 2015.

In January 2018, the board of directors of our general partner approved the final TUR for the four measurement periods of the 2015 performance unit grants, which are as follows:

Performance Period	Actual TUR (%)	Position	Percentile Ranking* (%)	Payout (% of target)**
January 1, 2015—December 31, 2015	(45.3)	11 <sup>th</sup>	9.09	—
January 1, 2016—December 31, 2016	3.2	9 <sup>th</sup>	27.27	54.54
January 1, 2017—December 31, 2017	17.5	1 <sup>st</sup>	100.00	200.00
January 1, 2015—December 31, 2017	(34.8)	10 <sup>th</sup>	10.00	—
			<b>Average:</b>	63.64

\* Sunoco Logistics Partners L.P. was removed from the peer group due to its acquisition by Energy Transfer Partners, L.P. in April 2017.

\*\* No payout occurs for ranking below the 25th percentile.

The resulting average of 63.64 percent of target provided for a payment equal to \$0.6364 per performance unit granted. The board of directors approved the following payout to Ms. Beall and Messrs. Heminger and Templin:

Name	Target Number of Performance Units	Compensation Committee Approved Payout (\$)
Gary R. Heminger	1,100,000	700,040
Pamela K.M. Beall	85,000	54,094
Donald C. Templin	250,000	159,100

The payout settled 25 percent in full value MPLX LP common units and 75 percent in cash. Mr. Hennigan, Mr. Bromley and Mr. Floerke were not eligible for a payout as these awards were made prior to their employment with our general partner.

***MPLX Performance Units Granted in 2016***

Performance units granted in 2016 have a performance cycle of January 1, 2016, through December 31, 2018 and use TUR as the sole performance metric. They remain outstanding and are included in the “Outstanding Equity Awards at 2017 Fiscal Year-End” table. Additional information about these grants, including the peer group used (which has been adjusted), can be found in the “Long-Term Incentive Compensation” section of our Annual Report on Form 10-K for the year ended December 31, 2016. ONEOK Partners L.P. and Sunoco Logistics Partners L.P. were removed from the peer group as ONEOK Partners L.P. was acquired by ONEOK Inc. and Sunoco Logistics Partners L.P. was acquired by Energy Transfer Partners, L.P.

***MPLX Performance Units Granted in 2017***

After an annual review of market practices, the board of directors of our general partner again made performance unit grants in February 2017. TUR will be used to determine 50 percent of the performance unit payout using the following approved peer group:

- Andeavor Logistics LP
- Buckeye Partners, L.P.
- Enbridge Energy Partners, L.P.
- Energy Transfer Partners, L.P.
- Enterprise Products Partners L.P.
- Magellan Midstream Partners, L.P.
- Phillips 66 Partners LP
- Plains All American Pipeline, L.P.
- Valero Energy Partners LP
- Western Gas Partners, LP
- Williams Partners L.P.

ONEOK Partners L.P. and Sunoco Logistic Partners L.P. were removed for 2017 as ONEOK Partners L.P. was acquired by ONEOK Inc. and Sunoco Logistics Partners L.P. was acquired by Energy Transfer Partners L.P.

DCF per MPLX LP common unit in 2019 will be used to determine the remaining 50 percent of the performance unit payout. The DCF-per-MPLX LP-common-unit metric was added by the Committee as it believes unitholders also place significance on DCF to measure a partnership’s performance relative to others in the same industry. Threshold, target and maximum levels are calculated using a CAGR of 8 percent, 10 percent and 12 percent, respectively, over the full-year 2016 DCF per MPLX LP common unit. The following table will be used to determine the DCF performance metric payout percentage for the 2017 grant:

	Full Year 2016	Threshold (50%)*	Target (100%)*	Maximum (200%)*
DCF per MPLX LP common unit	\$2.3465	\$2.9559	\$3.1232	\$3.2967

\* Payout for performance between threshold and target, and between target and maximum will be determined using linear interpolation.

The number of performance units granted to Ms. Beall and Messrs. Heminger, Templin, Bromley and Floerke can be found in the Grants of Plan-Based Awards table below. Mr. Hennigan did not receive performance units in 2017 as they were awarded prior to his hire on June 19, 2017.

***Phantom Units***

Grants of phantom units provide diversification of the mix of LTI awards, promote ownership of actual MPLX LP common units and promote retention. Further, phantom unit grants also help our NEOs increase their holdings in MPLX LP common units and achieve established unit ownership guideline levels.

The value of phantom unit awards is variable, based on the value of an underlying MPLX LP common unit, and the awards vest in equal installments on the first, second and third anniversary of the date of grant and are settled

in MPLX LP common units upon vesting. Prior to vesting, recipients have no right to vote the units, and cash distributions are accrued and paid in cash upon vesting. Upon vesting, a one-year holding period requirement is in effect for all full-value MPLX LP common units received under the MPLX 2012 Plan. This holding period prevents our NEOs from selling any MPLX LP common units for 12 months from the time the awards are vested. This requirement applies to units net of taxes at the time of vesting or distribution.

The number of phantom units granted to each of our NEOs can be found in the “Grants of Plan-Based Awards” table in this Annual Report on Form 10-K.

### **MPC Long-Term Incentive Compensation Program**

As part of their total equity package, each of our NEOs also receives LTI from our sponsor. MPC LTI awards for 2017 were granted in the form of performance units (40 percent), stock options (40 percent) and restricted stock (20 percent). The forms of awards differ as illustrated below:

<u>Form of LTI Award</u>	<u>Form of Settlement</u>	<u>Compensation Realized</u>
MPC Performance Units	25 percent in MPC common stock and 75 percent cash	\$0.00 to \$2.00 per unit based on MPC’s relative TSR ranking among a group of peers
MPC Stock Options	MPC common stock	Stock price appreciation from grant date to exercise date
MPC Restricted Stock	MPC common stock	Full value of common stock upon vesting

Due to the nature of LTI awards, the actual long-term compensation value realized by our NEOs will depend on the price of the underlying common stock at the time of settlement. The 2017 LTI awards were based on an intended dollar value rather than a specific number of performance units, stock options or shares of restricted stock.

MPC granted the 2017 LTI awards to Ms. Beall and Messrs. Bromley and Floerke on March 1, 2017. The exercise price for stock options is equal to the closing price of a share of MPC common stock on the grant date, or the first trading day thereafter if the grant date is not a trading day. We discuss each of the forms of LTI awards in more detail below.

### **MPC Performance Units**

The MPC Compensation Committee believes a performance unit program serves as a complement to the stock option and restricted stock programs. The program benchmarks MPC’s TSR relative to a peer group of oil industry competitors and a market index. This relative evaluation allows for the cyclical nature of its business and commodity prices (crude oil) to be recognized and prevents volatility from directly advantaging or disadvantaging the payout of the award beyond that of its peers. The MPC Compensation Committee continues to believe that TSR relative to a peer group is the single best metric for its performance unit program as it is commonly used by shareholders to measure a company’s performance relative to others within the same industry. It also aligns the compensation of its NEOs with the value delivered to its shareholders. The design of the performance unit program ensures MPC pays above target compensation only when its TSR is above the median of the peer group.

Under its program, TSR for MPC and each of the peer group companies is measured over a 36-month performance cycle. Each performance cycle has four equally weighted measurement periods: (1) the first 12 months, (2) the second 12 months, (3) the third 12 months, and (4) the entire 36-month period. The MPC Compensation Committee believes that measuring TSR over four measurement periods in the 36-month performance cycle is appropriate and serves the best interests of its shareholders. By having four equally weighted measurement periods, attaining maximum payout based on TSR may be achieved only by outperforming the TSR peer group for all four measurement periods.

Each peer group member's TSR is determined by taking the sum of the company's stock price appreciation or reduction, plus its cumulative cash dividends, for each measurement period and dividing that total by the company's beginning stock price for that period, as illustrated below:

$$\frac{(\text{Ending Stock Price} - \text{Beginning Stock Price}) + \text{Cumulative Cash Dividends}}{\text{Beginning Stock Price}}$$

The beginning and ending stock prices used for MPC and each peer group member in the TSR calculation are the averages of the respective closing stock prices for the 20 trading days immediately preceding the beginning and ending date of the applicable measurement period. The design mitigates significant market fluctuations in stock price at the beginning or end of a performance cycle and discourages excessive or inappropriate risk-taking near the end of a performance cycle by limiting the impact on the overall payout of the award.

MPC's TSR performance percentile within the peer group is measured for each measurement period, with the related payout percentage determined using the following table. However, if MPC's TSR is negative for a measurement period, the payout percentage for that measurement period is capped at target (100 percent) regardless of actual relative TSR performance percentile. We refer to this provision as a "negative TSR cap".

TSR Percentile	Payout (% of Target)*
100 <sup>th</sup> (Highest)	200%
50 <sup>th</sup>	100%
25 <sup>th</sup>	50%
Below 25 <sup>th</sup>	0%

\* Payout for performance between quartiles will be determined using linear interpolation.

Each performance unit is dollar denominated with a target value of \$1.00. The actual payout may vary from \$0.00 to \$2.00 (zero percent to 200 percent of target). The MPC Compensation Committee also believes that having the maximum payout capped at \$2.00 per unit mitigates excessive or inappropriate risk-taking. The final value of the performance unit award will be determined by multiplying the simple average of the payout percentages for the four measurement periods by the number of performance units granted. These awards settle 25 percent in MPC common stock and 75 percent in cash.

### MPC Performance Units Granted in 2015

Performance units granted by MPC in 2015 had a performance cycle of January 1, 2015, through December 31, 2017. Additional information about these grants, including the peer group used, can be found in the "Long-Term Incentive Compensation Program" section of the MPC 2016 Proxy Statement.

In January 2018, the MPC Compensation Committee certified the final TSR for the four measurement periods of the 2015 performance unit grants, which are as follows:

Performance Period	Actual TSR (%)	Position	Percentile Ranking (%)	Payout (% of target)
January 1, 2015—December 31, 2015	20.2	5 <sup>th</sup>	42.85	85.70
January 1, 2016—December 31, 2016	(1.8)	5 <sup>th</sup>	42.85	85.70
January 1, 2017—December 31, 2017	34.6	3 <sup>rd</sup>	71.43	142.86
January 1, 2015—December 31, 2017	57.0	2 <sup>nd</sup>	85.71	171.42
			<b>Average:</b>	121.42

The resulting average of 121.42 percent of target provided for a payment equal to \$1.2142 per performance unit granted. As a result, the MPC Compensation Committee approved the following payment to Ms. Beall:

<u>Name</u>	<u>Target Number of Performance Shares</u>	<u>MPC Compensation Committee Approved Payout (\$)</u>
Pamela K.M. Beall	272,000	330,263

The results of the 2015 performance unit grant were certified by the MPC Compensation Committee and settled 25 percent in full value shares of MPC common stock and 75 percent in cash. Mr. Hennigan, Mr. Bromley and Mr. Floerke were not eligible for a payout as these awards were made prior to their employment date.

### **MPC Performance Units Granted in 2016**

Performance units granted by MPC in 2016 have a performance cycle of January 1, 2016, through December 31, 2018. They remain outstanding and are included for Ms. Beall in the “Outstanding Equity Awards at 2017 Fiscal Year-End” table. Additional information about these grants, including the peer group used, can be found in the “Long-Term Incentive Compensation Program” section of the MPC 2017 Proxy Statement.

### **MPC Performance Units Granted in 2017**

The MPC Compensation Committee made the decision to award performance unit grants in February 2017. The MPC Compensation Committee approved the following peer group for performance unit awards granted in 2017:

- Andeavor
- Chevron Corporation
- HollyFrontier Corporation
- PBF Energy
- Phillips 66
- Valero Energy Corporation
- S&P 500 Energy Index

The number of performance units granted to Ms. Beall and Messrs. Bromley and Floerke can be found in the “Grants of Plan-Based Awards” table.

### **MPC Stock Options**

Stock options provide a direct but variable link between our NEOs’ long-term compensation and the long-term value shareholders receive by investing in MPC. The MPC Compensation Committee believes stock options are inherently performance-based as option holders only realize benefits if the value of the stock increases for all shareholders after the grant date. The exercise price of MPC stock options is generally equal to the per-share closing price of MPC common stock on the grant date. Stock options vest in equal installments on the first, second and third anniversary of the date of grant and have a maximum 10-year term during which an NEO may exercise the options. Option holders do not have voting rights or receive dividends on the underlying common stock.

The number of options granted to Ms. Beall and Messrs. Bromley and Floerke can be found in the “Grants of Plan-Based Awards” table.

### **MPC Restricted Stock**

Grants of restricted stock provide diversification in the mix of LTI awards, result in ownership of actual shares of common stock and promote NEO retention.



The value of restricted stock awards is also variable, and the awards vest in equal installments on the first, second and third anniversary of the date of grant. Prior to vesting, recipients have voting rights but dividends declared during the restricted period are accrued and paid in cash upon vesting. Upon vesting, a one-year holding period requirement is in effect for all full-value shares received under MPC's incentive compensation plan. This holding period prevents our NEOs and other executive officers from selling any stock or performance units settled in shares for 12 months from the time the awards are vested or earned. This requirement applies to shares net of taxes at the time of vesting or distribution.

The number of restricted shares granted to Ms. Beall and Messrs. Hennigan, Bromley and Floerke can be found in the "Grants of Plan-Based Awards" table.

## **OTHER POLICIES**

### **Benefit Programs and Perquisites**

We do not sponsor any benefit plans, programs or policies such as healthcare, life insurance, income protection or retirement benefits for our NEOs, and we do not provide them with perquisites. However, those types of benefits are generally provided to our NEOs in connection with their employment by MPC or its affiliates and are governed in all cases by the terms of the applicable plan documents. All determinations with respect to such benefits will be made by MPC, or the plans, as the case may be, without input from us or our general partner or its board of directors. MPC bears the full cost of any such programs for our NEOs and no portion of these benefits is charged back to us under the provisions of the omnibus agreement. However, we have summarized the material elements of these MPC programs below to the extent they represent a material component of our NEOs' compensation for the services they provide to our business.

### **Perquisites**

Our NEOs are eligible for reimbursement for certain tax, estate and financial planning services up to \$15,000 per year while actively employed by MPC or its affiliates and \$3,000 in the year following retirement or death. The MPC Compensation Committee believes this perquisite is appropriate due to the complexities of income tax preparation for our NEOs, who may, for example, be required to make personal income tax filings in multiple states due to receiving equity compensation that settle in MPLX LP common units.

Our NEOs are also eligible for enhanced annual physical health examinations to promote their health and well-being. Under this program, our NEOs can receive a comprehensive physical (generally in the form of a one-day appointment), with procedures similar to those available to all other employees who participate in MPC's health program. The incremental cost of these enhanced physicals is primarily attributable to MPC-paid facilities charges and incremental charges incurred for not using facilities from which MPC receives discounts under the health plan network.

The primary use of corporate aircraft is for business purposes and must be authorized by MPC's Chairman and CEO or another executive officer designated by MPC's Board or MPC's Chairman and CEO. Occasionally, spouses or other guests will accompany our NEOs on corporate aircraft, or our NEOs may travel for personal purposes on corporate aircraft typically in cases where space is available on business-related flights. However, Mr. Hennigan was granted limited personal use of the aircraft when otherwise available during the first 12 months of his employment as MPLX President. When a spouse's or guest's travel does not meet the Internal Revenue Service standard for business use, the cost of that travel is imputed as income to the NEO.

Reportable values for these perquisite programs, based on the incremental costs to MPC, are included in the "All Other Compensation" column of the 2017 Summary Compensation Table.

Neither income tax assistance nor tax gross-ups are provided on executive perquisites including tax, estate and financial planning services or the personal use of corporate aircraft.

### **Unit Ownership Guidelines**

The board of directors of our general partner has approved unit ownership guidelines for our executive officers including our NEOs. As our executive officers earn a base salary from MPC and not from MPLX, the unit ownership guidelines were established as a fixed number of MPLX LP common units instead of a value representing a multiple of an executive officer's annual salary. The guidelines are intended to align the long-term interests of our executive officers and our unitholders. Under these guidelines, executive officers are expected to hold a specified level of MPLX LP common units. The targeted levels are:

- based on the executive's position and responsibilities, and
- expected to be reached within five years of the executive officer's assumption of the position.

The unit ownership guidelines are as follows:

- Chairman of the Board and Chief Executive Officer—25,000 MPLX LP common units;
- President—20,000 MPLX LP common units;
- Executive Vice President—15,000 MPLX LP common units;
- Senior Vice President—10,000 MPLX LP common units; and
- Vice President—5,000 MPLX LP common units.

Executive officers are not permitted to sell any MPLX LP common units received under the MPLX 2012 Plan unless their ownership guideline levels are met and are maintained after the sale. Additionally, a one-year holding requirement prevents executive officers from selling any MPLX LP common units distributed in settlement of phantom units or performance units for twelve months from the time they are vested. This requirement applies to MPLX LP common units net of taxes at the time of vesting or distribution. All of our NEOs have met their MPLX LP common unit ownership guidelines.

### **Prohibition on Derivatives and Hedging**

In order to ensure our executive officers, including our NEOs, bear the full risk of MPLX LP common unit ownership, we maintain a policy that prohibits hedging transactions related to our units, or pledging or creating security interests in our units, including units in excess of a unit ownership guideline requirement.

### **Severance and Change in Control Arrangements**

None of our NEOs have employment agreements with us, our general partner or MPC. Our NEOs are eligible to participate in MPC's Amended and Restated Executive Change in Control Severance Benefits Plan (the "MPC CIC Plan") and MPLX's Executive Change in Control Severance Benefits Plan (the "MPLX CIC Plan"). These plans generally provide senior executives with severance payments and benefits in the event of a qualified termination of employment within two years of the occurrence of a change in control of MPC and/or MPLX. All determinations with respect to such benefits would be made by the board of directors of MPC in the event of a change in control of MPC, or the board of directors of our general partner in the event of a change in control of MPLX.

Our NEOs do not participate in any arrangements that would result in the payment of any amounts or provision of any benefits solely as a result of a change in control of us. However, pursuant to the MPLX CIC Plan, vesting of all of the NEOs' long-term incentive awards in us would be accelerated upon a qualified termination from service with us in connection with a change in control of MPLX.

For additional information about the severance and accelerated vesting that may be provided under the MPLX CIC Plan, please refer to the discussion below under the heading "Potential Payments Upon Termination or Change in Control."

If either Messrs. Bromley or Floerke separate from service as a result of a forced relocation of his principal place of employment to a location more than 50 miles from his current principal place of employment, his unvested MPLX LP phantom units and MPC restricted stock received as part of his retention grants awarded in 2015 will vest and become payable. The amount payable assuming such termination occurred on December 31, 2017, based on the MPLX LP common unit and MPC common stock closing prices as of that date, or the last trading day prior to that date if not a trading day, would have been as follows: Mr. Bromley, \$3,396,597; and Mr. Floerke, \$2,917,255.

Additionally, upon either of Messrs. Bromley's or Floerke's separation from service without cause, the separated NEO is entitled to a portion of the grant of MPLX LP phantom units received as part of his retention grants awarded in 2015. The amount payable assuming such separation of service occurred on December 31, 2017, based on the MPLX LP common unit closing price as of that date, or the last trading date prior to that date if not a trading day, would have been as follows: Mr. Bromley, \$1,782,013; and Mr. Floerke, \$1,293,804.

Mr. Bromley retired effective January 1, 2018.

### **Recoupment/Clawback Policy**

In addition to any compensation recoupment policies that apply with respect to the compensation our NEOs receive from MPC, the MPLX 2012 Plan provides that all awards granted under the MPLX 2012 Plan will be subject to clawback or recoupment in the case of certain forfeiture events. If the Partnership is required, pursuant to a determination made by the SEC or the audit committee of our general partner, to prepare a material accounting restatement due to our non-compliance with any financial reporting requirement under applicable securities laws as a result of misconduct, the audit committee may determine that a forfeiture event has occurred based on an assessment of whether an executive officer:

- knowingly engaged in misconduct;
- was grossly negligent with respect to misconduct;
- knowingly failed or was grossly negligent in failing to prevent misconduct; or
- engaged in fraud, embezzlement or other similar misconduct materially detrimental to us.

Upon a determination by the audit committee of our general partner that a forfeiture event has occurred, any grants of unvested phantom units and performance units to such executive officer would be subject to immediate forfeiture. If a forfeiture event occurred either while the executive officer is employed or within three years after termination of employment and a payment has previously been made to the executive officer in settlement of performance units, we may recoup an amount in cash or units up to (but not in excess of) the amount paid in settlement of the performance units.

These recoupment provisions are in addition to the requirements in Section 304 of the Sarbanes-Oxley Act of 2002, which provide that the Chief Executive Officer and Chief Financial Officer shall reimburse us for incentive-based or equity-based compensation, as well as any related profits received in the 12-month period prior to the filing of an accounting restatement due to non-compliance with financial reporting requirements as a result of our misconduct. Additionally, all equity grants made since 2013 include provisions making them subject to any clawback provisions required by the Dodd-Frank Act and any other "clawback" provisions as required by law or by the applicable listing standards of the exchange on which the MPLX LP common units are listed for trading.

### **Additional Compensation Components**

In the future, as MPC and/or our general partner formulate and implement the compensation programs for our executive officers, MPC and/or our general partner may provide additional or different compensation

components, benefits and/or perquisites to help ensure our executive officers are provided with a balanced, comprehensive and competitive total compensation package. We, MPC and our general partner believe that it is important to maintain flexibility to adapt compensation structures on an ongoing basis to properly attract, motivate, retain and reward the top executive talent for which we, MPC and our general partner compete with other companies.

#### **COMPENSATION-BASED RISK ASSESSMENT**

Annually, the Committee reviews our policies and practices in compensating our service providers (including both executive officers and non-executives, if any) as they relate to our risk management profile.

The Committee completed this review of our 2017 programs in February 2018. As a result of this review, the Committee concluded that any risks arising from our compensation policies and practices were not reasonably likely to have a material adverse effect on our financial statements.

#### **RATIO OF ANNUAL COMPENSATION FOR THE CEO TO OUR MEDIAN EMPLOYEE**

We do not determine the total compensation of our chief executive officer or of any of the other personnel responsible for managing and operating our business, all of whom are employed by MPC and not by us or our general partner. Because we do not have any employees and do not determine or pay total compensation to the employees of MPC who manage and operate our business, we do not have a median employee whose total compensation can be compared to the total compensation of our chief executive officer.

## Summary Compensation Table

The following table summarizes the total compensation awarded to, earned by or paid to our NEOs for the services each provided to our business:

Name and Principal Position <sup>(1)</sup>	Year	Salary <sup>(2)</sup> (\$)	Bonus <sup>(3)</sup>	Stock Awards <sup>(4)(5)</sup> (\$)	Option Awards <sup>(4)</sup> (\$)	Non-Equity Incentive Plan Compensation <sup>(6)</sup> (\$)	Change in Pension Value and Nonqualified Deferred Compensation Earnings <sup>(7)</sup> (\$)	All Other Compensation <sup>(8)</sup> (\$)	Total (\$)
<b>Gary R. Heminger</b> Chairman of the Board and Chief Executive Officer	2017	1,310,000		2,282,185	—	—	—	—	3,592,185
	2016	1,220,000		1,797,853	—	—	—	—	3,017,853
	2015	1,220,000		2,239,071	—	—	—	—	3,459,071
<b>Pamela K.M. Beall</b> Executive Vice President and Chief Financial Officer	2017	525,000		743,215	68,010	670,000	245,643	88,828	2,340,696
	2016	499,667		529,759	170,008	550,000	226,408	86,067	2,061,909
	2015	234,375		173,033	—	262,500	56,514	39,282	765,704
<b>Michael J. Hennigan</b> President	2017	429,589	1,000,000	5,000,052	—	800,000	126,322	157,086	7,513,049
	2016	465,000		655,807	60,007	—	104,446	67,884	1,353,144
	2015	461,250		—	—	450,000	90,486	61,251	1,062,987
<b>C. Corwin Bromley</b> Executive Vice President and General Counsel	2017	34,615		3,525,011	—	—	—	—	3,559,626
	2016	442,500		699,511	64,009	600,000	78,750	67,633	1,952,403
	2015	415,000		—	—	425,000	62,847	55,179	958,026
<b>Gregory S. Floerke</b> Executive Vice President, MarkWest Operations	2017	30,769		3,092,492	—	—	—	—	3,123,261
	2016	365,625		2,282,185	—	765,000	128,453	76,702	3,617,965
	2015	720,000		1,225,803	—	1,170,000	217,355	134,794	3,467,952
<b>Donald C. Templin</b> Former President, MPLX	2017	515,000		508,906	—	—	—	—	1,023,906

- (1) Except where indicated, amounts shown reflect only compensation amounts allocable to MPLX LP and do not include compensation amounts for other services that are not allocable to MPLX LP. For 2017, compensation amounts were allocated based on the relative percentage each NEO's business time was dedicated to MPLX LP's business. For 2017, percentage allocations for each NEO were as follows: Mr. Templin-90 percent; Ms. Beall and Messrs. Bromley, Floerke and Hennigan-100 percent.
- (2) The amounts shown in this column reflect the annualized fixed fee for Mr. Heminger for 2017, 2016, and 2015 and for Mr. Templin for 2015. The amount shown for Mr. Floerke for 2017 reflects three months at his January 1, 2017 annualized base salary and nine months at his April 1, 2017 annualized base salary, respectively. The amount shown for Mr. Hennigan is a pro-rated amount of his annualized base salary since his hire date on June 19, 2017. The amount shown for Mr. Templin reflects three months at his January 1, 2017 annualized base salary and three months at his April 1, 2017 annualized base salary, respectively, to reflect his tenure as President, MPLX, which ended on June 20, 2017. Ms. Beall's and Mr. Bromley's amounts reflect their annualized base pay as of December 31, 2017 as they did not receive a base pay adjustment in 2017.
- (3) The amount in this column for Mr. Hennigan reflects a cash sign-on bonus.
- (4) The amounts shown in this column reflect the aggregate grant date fair value in accordance with provisions of the Financial Accounting Standards Board Accounting Standards Codification 718, Compensation-Stock Compensation (FASB ASC Topic 718.) See Item 8. Financial Statements and Supplementary Data-Note 20 for assumptions used in the calculation of the amounts related to MPLX LP equity for the year ended December 31, 2017, Note 20 to financial statements as reported on our Annual Report on Form 10-K for assumptions used in the calculation of the amounts related to MPLX LP equity for the year ended December 31, 2016, and Note 19 to financial statements as reported on our Annual Report on Form 10-K for assumptions used in the calculation of the amounts related to MPLX LP equity for the year ended December 31, 2015; and Note 23 to MPC's financial statements as reported on its Annual Reports on

Form 10-K for the years ended December 31, 2017, and December 31, 2016, for amounts related to MPC equity. Amounts in this column for 2016 performance unit grants were previously overstated and have been decreased to reflect the correction of an error in the Monte Carlo valuation model used to determine the grant date fair value of the units.

- (5) The maximum value of the performance units reported in this column for those who received 2015 performance unit grants assuming the highest level of performance is achieved, for each NEO, is as follows: Mr. Heminger, MPLX—\$2,200,000; Ms. Beall, MPLX—\$170,000 and MPC—\$544,000; and Mr. Templin, MPLX—\$500,000. The maximum value of the performance units reported in this column for those who received 2016 performance unit grants assuming the highest level of performance is achieved, for each NEO, is as follows: Mr. Heminger, MPLX—\$2,200,000; Ms. Beall, MPLX—\$425,000 and MPC—\$340,000; and Mr. Templin, MPLX—\$1,500,000. The maximum value of the performance units reported in this column for those receiving 2017 performance unit grants, assuming the highest level of performance is achieved, for each NEO, is as follows: Mr. Heminger, MPLX—\$2,400,000; Ms. Beall, MPLX—\$680,000 and MPC—\$136,000; Mr. Templin, MPLX—\$2,400,000; Mr. Bromley, MPLX—\$600,000 and MPC—\$120,000; and Mr. Floerke, MPLX—\$640,000 and MPC—\$128,000.
- (6) The amounts shown in this column reflect the total value of ACB awards earned in the year indicated, which were paid in the following year.
- (7) The amounts shown in this column reflect the annual change in actuarial present value of accumulated benefits under the Marathon Petroleum retirement plans. See “Post-Employment Benefits for 2017” and “Marathon Petroleum Retirement Plans” sections of the “Compensation Discussion and Analysis” for more information regarding the defined benefit plans and the assumptions used in the calculation of these amounts. There are no deferred compensation earnings reported in this column as the non-qualified deferred compensation plans do not provide above-market or preferential earnings.
- (8) In connection with their employment with MPC, our NEOs are eligible for limited perquisites which, together with contributions to defined contribution plans, comprise the amounts reported in the All Other Compensation column. The amounts shown in this column are summarized below:

Name	Personal Use of Company Aircraft <sup>(a)</sup> (\$)	Company Physicals <sup>(b)</sup> (\$)	Tax & Financial Planning <sup>(c)</sup> (\$)	Security (\$)	Miscellaneous Perks & Tax Allowance Gross-ups (\$)	Company Contributions to Defined Contribution Plans <sup>(d)</sup> (\$)	Total All Other Compensation (\$)
Gary R. Heminger	—	—	—	—	—	—	—
Pamela K.M. Beall	—	3,651	12,385	—	—	72,792	88,828
Michael J. Hennigan	55,155	3,651	—	—	—	98,280	157,086
C. Corwin Bromley	—	3,651	—	—	—	64,233	67,884
Gregory S. Floerke	—	3,651	3,165	—	—	60,817	67,633
Donald C. Templin	—	3,651	5,229	—	—	67,822	76,702

- (a) The primary use of corporate aircraft is for business purposes and must be authorized by MPC’s Chairman and CEO or another executive officer designated by MPC’s Board or MPC’s Chairman and CEO. Occasionally, spouses or other guests will accompany our NEOs on corporate aircraft, or our NEOs may travel for personal purposes on corporate aircraft typically in cases where space is available on business-related flights. However Mr. Hennigan was granted limited personal use of the aircraft when otherwise available during the first 12 months of his employment as MPLX President. The amounts shown in this column reflect the aggregate incremental cost of personal use of corporate aircraft by our NEOs for the period from January 1, 2017, through December 31, 2017. These amounts reflect our incremental cost of travel on corporate aircraft for our NEOs, their spouses or other guests for personal travel. We have estimated our aggregate incremental cost using a methodology that reflects the average costs of operating the aircraft, such as fuel costs, trip-related maintenance, crew travel expenses, trip-related fees, storage costs, communications charges and other miscellaneous variable costs. Fixed costs, such as pilot compensation, the purchase and lease of aircraft and maintenance not related to travel are excluded from this calculation. We believe this method provides a reasonable estimate of our incremental cost. However, use of this method overstates the actual incremental cost when a flight has a primary business purpose, space is available to transport an officer or his or her guest not traveling for business purposes and no incremental cost is realized by us. No income tax assistance or gross-ups are provided for personal use of corporate aircraft.

- (b) All MPC employees, including our NEOs, are eligible to receive an annual physical. Executives may receive an enhanced physical under the executive physical program. The amounts shown in this column reflect the average incremental cost of the executive physical program in excess of the average incremental cost of the employee physical program. Due to privacy concerns and Health Insurance Portability and Accountability Act confidentiality requirements, we do not disclose actual usage or cost of this program by individual NEOs.
- (c) The amounts shown in this column reflect reimbursement for the costs of professional advice related to tax, estate and financial planning up to a specified maximum not to exceed \$15,000 per calendar year. For information on this program refer to the “Perquisites” section of the “Compensation Discussion and Analysis.”
- (d) The amounts shown in this column reflect amounts contributed by MPC under the tax-qualified Marathon Petroleum Thrift Plan for Ms. Beall and Messrs. Bromley, Floerke, Hennigan and Templin, as well as under related non-qualified deferred compensation plans. See “Post-Employment Benefits for 2017” and “Marathon Petroleum Retirement Plans” sections of the “Compensation Discussion and Analysis” for more information.

### Grants of Plan-Based Awards in 2017

The following table provides information regarding all plan-based awards, including cash-based incentive awards and equity-based awards (specifically stock options, restricted stock, phantom units and performance units) granted to each of our NEOs in 2017 for the services each provided to our business:

Name	Type of Award	Grant Date	Approval Date <sup>(1)</sup>	Estimated Future Payouts Under Non-Equity Incentive Plan Awards <sup>(2)</sup>			Estimated Future Payouts Under Equity Incentive Plan Awards <sup>(3)</sup>			All Other Shares of Stock or Units (#)	All Other Option Awards: Underlying Options (#)	Exercise or Base Price of Option Awards (\$)	Grant Date And Option Awards <sup>(4)</sup> (\$)
				Threshold (\$)	Target (\$)	Maximum (\$)	Threshold (\$)	Target (\$)	Maximum (\$)				
Gary R. Heminger	MPLX LP Phantom Units	3/1/2017	2/21/2017							31,563		1,200,025	
	MPLX LP Performance Units	3/1/2017	2/21/2017				150,000	1,200,000	2,400,000			1,082,160	
Pamela K.M. Beall	MPC Stock Options	3/1/2017	2/21/2017								4,776	50.99	68,010
	MPC Restricted Stock	3/1/2017	2/21/2017							667			34,010
	MPC Performance Units	3/1/2017	2/21/2017				8,500	68,000	136,000				62,580
	MPC Annual Cash Bonus			N/A	367,500	735,000							
	MPLX LP Phantom Units	3/1/2017	2/21/2017							8,943			340,013
	MPLX LP Performance Units	3/1/2017	2/21/2017				42,500	340,000	680,000				306,612
	MPC Restricted Stock	7/1/2017	5/30/2017							18,833			1,000,032
	MPC Annual Cash Bonus			N/A	429,589	859,178							
	MPLX LP Phantom Units	7/1/2017	5/30/2017							116,823			4,000,020
C. Corwin Bromley	MPC Stock Options	3/1/2017	2/21/2017								4,214	50.99	60,007
	MPC Restricted Stock	3/1/2017	2/21/2017							589			30,033
	MPC Performance Units	3/1/2017	2/21/2017				7,500	60,000	120,000				55,218
	MPC Annual Cash Bonus			N/A	279,000	558,000							
	MPLX LP Phantom Units	3/1/2017	2/21/2017							7,891			300,016
	MPLX LP Performance Units	3/1/2017	2/21/2017				37,500	300,000	600,000				270,540



Name	Type of Award	Grant Date	Approval Date <sup>(1)</sup>	Estimated Future Payouts Under Non-Equity Incentive Plan Awards <sup>(2)</sup>			Estimated Future Payouts Under Equity Incentive Plan Awards <sup>(3)</sup>			All Other Shares of Stock or Units (#)	All Other Option Awards: Underlying Options (#)	Exercise or Base Price of Option Awards (\$)	Grant Date And Option Awards <sup>(4)</sup> (\$)
				Threshold (\$)	Target (\$)	Maximum (\$)	Threshold (\$)	Target (\$)	Maximum (\$)				
Gregory S. Floerke	MPC Stock Options	3/1/2017	2/21/2017								4,495	50.99	64,009
	MPC Restricted Stock	3/1/2017	2/21/2017						628				32,022
	MPC Performance Units	3/1/2017	2/21/2017				8,000	64,000	128,000				58,899
	MPC Annual Cash Bonus			N/A	315,000	630,000							
	MPLX LP Phantom Units	3/1/2017	2/21/2017							8,417			320,014
	MPLX LP Performance Units	3/1/2017	2/21/2017				40,000	320,000	640,000				288,576
Donald C. Templin	MPC Annual Cash Bonus			N/A	405,000	810,000							
	MPLX LP Phantom Units	3/1/2017	2/21/2017							31,563			1,200,025
	MPLX LP Performance Units	3/1/2017	2/21/2017				150,000	1,200,000	2,400,000				1,082,160

- (1) The MPC Compensation Committee and our Board approved the awards reported in the table above for Ms. Beall and Messrs. Heminger, Bromley, Floerke and Templin on February 21, 2017, with a grant date of March 1, 2017. The MPC Compensation Committee and our Board approved the awards reported in the table above for Mr. Hennigan on May 30, 2017, with a grant date of July 1, 2017.
- (2) The target amounts shown in this column reflect the target annual incentive opportunity. No threshold amount is disclosed as the MPC Compensation Committee has discretion to not award an annual incentive under the ACB program. Each NEO may generally earn a maximum of 200 percent of the target.
- (3) The target amounts shown in this column reflect the number of performance units granted to Ms. Beall and Messrs. Heminger, Bromley, Floerke and Templin. Each performance unit has a target value of \$1.00. The threshold for the award is the minimum possible payout of the award, which is 12.5 percent. The threshold is achieved when the payout percentage is 50 percent for one performance period and zero percent for the other three performance periods, thus an average payout percentage of 12.5 percent for the performance cycle. The maximum payout for this award is 200 percent of target.
- (4) The amounts shown in this column reflect the total grant date fair value of MPC stock options, MPC restricted stock, MPLX LP phantom units and MPC/MPLX LP performance units granted in 2017 in accordance with provisions of the Financial Accounting Standards Board Accounting Standards Codification 718, Compensation-Stock Compensation (“FASB ASC Topic 718”). The Black-Scholes value used for the stock options was \$14.24 per share. The restricted stock value was based on the MPC closing stock price on the grant date listed, or the next business day if the grant date was not a business day. The price used for the March 1, 2017, grants of MPC restricted stock awards was \$50.99 per share. The price used for the July 1, 2017, grants of MPC restricted stock awards was the closing price on July 3, 2017, of \$53.10 per share. MPC performance units are designed to settle 25 percent in MPC common stock and 75 percent in cash. The MPC performance units have a grant date fair value of \$0.9203 per unit as calculated using a Monte Carlo valuation model. Assumptions used in the calculation of these amounts are

included in Note 23 to MPC's financial statements as reported on its Annual Report on Form 10-K for the year ended December 31, 2017. The phantom unit value was based on the MPLX LP common unit closing price on the grant date listed, or the next business day if the grant date was not a business day. The price used for the March 1, 2017, grants of MPLX LP phantom unit awards was \$38.02 per unit. The price used for the July 1, 2017, grants of MPLX LP phantom unit awards was the closing price on July 3, 2017, of \$34.24 per unit. MPLX LP performance units are designed to settle 25 percent in MPLX LP common units and 75 percent in cash. The MPLX LP performance units have a weighted grant date fair value of \$0.9018 per unit, which is calculated using a Monte Carlo valuation model of \$0.8036 for the TUR portion (50%) and target value of \$1.00 for the DCF portion (50%). See Item 8. Financial Statements and Supplementary Data-Note 20 for assumptions used in the calculation of these amounts.

### **MPC Stock Options (Option Awards)**

The MPC Compensation Committee granted stock options to Ms. Beall and Messrs. Bromley and Floerke with a grant date of March 1, 2017. All options vest in one-third increments on the first, second and third anniversaries of the date of grant and expire 10 years following the date of grant. No dividends are paid and there are no voting rights associated with stock options. In the event of the death or retirement (whether mandatory or not) of an NEO, unvested options granted to such NEO as an officer immediately vest and remain exercisable until the earlier of five years following the date of death or retirement or the original expiration date. Unvested options granted to an NEO as a non-officer immediately vest and remain exercisable until the earlier of three years following the date of death or retirement or the original expiration date. In the event of a change in control of MPC and a Qualified Termination, unvested options immediately vest and remain exercisable for the original term of the option. Upon voluntary or involuntary termination of an NEO, unvested options are forfeited. Upon voluntary or involuntary termination of an NEO for cause, vested options are cancelled. Upon involuntary termination of an NEO without cause, vested options are exercisable for 90 days following the date of termination.

### **MPC Restricted Stock (Stock Awards)**

The MPC Compensation Committee granted annual restricted stock awards to Ms. Beall and Messrs. Bromley and Floerke with a grant date of March 1, 2017, and to Mr. Hennigan with a grant date of July 1, 2017, which vest in one-third increments on the first, second and third anniversaries of the grant date. The MPC Compensation Committee also granted Mr. Hennigan restricted stock on July 1, 2017, which fully vests on the third anniversary of the grant date. Dividends accrue on the restricted stock awards and are paid upon vesting. There are voting rights associated with unvested restricted stock awards. If an NEO retires under MPC's mandatory retirement policy, unvested restricted stock vests and accrued dividends are paid upon the mandatory retirement date (the first day of the month coincident with or following the officer's 65th birthday). In the event of the death of an NEO or a change in control of MPC, unvested restricted stock immediately vests and accrued dividends are paid. If an NEO retires or otherwise leaves MPC prior to the vesting date, unvested restricted stock and accrued but unpaid dividends are forfeited.

### **MPC Performance Units (Equity Incentive Plan Awards)**

The MPC Compensation Committee granted annual performance units to Ms. Beall and Messrs. Bromley and Floerke with a grant date of March 1, 2017. Each performance unit has a target value of \$1.00 and is designed to settle 25 percent in MPC common stock and 75 percent in cash. Payout of these units could vary from \$0.00 to \$2.00 per unit and is tied to MPC's TSR over a 36-month period as compared to the TSR of those in its peer group for the January 1, 2017, through December 31, 2019, performance period. No dividends are paid and there are no voting rights associated with unvested performance units. If an NEO retires following the completion of nine months of the performance period, the NEO will be eligible to receive, at the MPC Compensation Committee's discretion, a prorated payout based on the actual results of the entire performance period. If an NEO retires under MPC's mandatory retirement policy, outstanding performance units will fully vest, however payout

will occur at the end of the full 36-month performance cycle based on the certified results of the performance cycle. In the event of the death of an NEO, all unvested performance units immediately vest at target levels. In the event of a change in control of MPC and a Qualified Termination (as defined following the “Potential Payments upon Termination or Termination in the Event of a Change in Control” table), unvested performance units will vest and be paid out based on MPC’s actual TSR performance amongst its specified peer group for the period from the date of grant to the date of the change in control, and target TSR performance for the period from the date of the change in control to the end of the performance cycle. If an NEO terminates employment under any other circumstance, unvested performance units are forfeited.

#### **MPC Annual Cash Bonus (Non-Equity Incentive Plan Awards)**

The MPC Compensation Committee established the ACB program as a variable incentive program intended to motivate and reward NEOs for achieving short-term (annual) business objectives that drive overall MPC shareholder and MPLX LP unitholder value while encouraging responsible risk-taking and accountability. Bonuses are determined at the discretion of the MPC Compensation Committee and the achievement of pre-established goals. If an NEO retires on or after July 1 of the performance year, eligibility for a bonus is at the MPC Compensation Committee’s discretion. In the event of the death of an NEO during the performance period, unless otherwise determined by the MPC Compensation Committee, a target bonus will be paid. In the event of change in control of MPC, a cash severance is paid in lieu of a bonus. If an NEO terminates employment under any other circumstance, the NEO will be ineligible for a bonus payment.

#### **MPLX LP Phantom Units (Other Unit Awards)**

The MPLX Board granted annual phantom unit awards to Ms. Beall and Messrs. Heminger, Bromley, Floerke and Templin with a grant date of March 1, 2017, and to Mr. Hennigan with a grant date of July 1, 2017. The phantom unit awards vest in one-third increments on the first, second and third anniversaries of the grant date. The MPLX Board also granted annual phantom unit awards to Mr. Hennigan on July 1, 2017, which fully vest on the third anniversary of the grant date. Distribution equivalents accrue on the phantom unit awards and are paid upon vesting. There are no voting rights associated with unvested phantom units. If an NEO retires under MPC’s mandatory retirement policy, unvested phantom units vest and accrued distribution equivalents are paid upon the mandatory retirement date (the first day of the month coincident with or following the officer’s 65th birthday.) In the event of the death of an NEO or a change in control of MPLX LP, unvested phantom units immediately vest and accrued distribution equivalents are paid. If an NEO retires or otherwise leaves MPLX prior to the vesting date, unvested phantom units and unpaid distribution equivalents are forfeited.

#### **MPLX LP Performance Units (Equity Incentive Plan Awards)**

The MPLX Board granted annual performance units to Ms. Beall and Messrs. Heminger, Bromley, Floerke and Templin with a grant date of March 1, 2017. Each performance unit has a target value of \$1.00 and is designed to settle 25 percent in MPLX LP common units and 75 percent in cash. Payout of these units could vary from \$0.00 to \$2.00 per unit and is tied to MPLX LP’s TUR over a 36-month period as compared to the TUR of those in a peer group for the January 1, 2017 through December 31, 2019 performance period and a DCF goal for the calendar year 2019. No cash distributions are paid and there are no voting rights associated with unvested performance units. If an NEO retires following the completion of nine months of the performance period, the NEO will be eligible to receive, at the discretion of the MPLX Board, a prorated payout based on the actual results of the entire performance period. If an NEO retires under MPC’s mandatory retirement policy, outstanding performance units will fully vest, however payout will occur at the end of the full 36-month performance cycle based on the approved results of the performance cycle. In the event of the death of an NEO, all unvested performance units immediately vest at target levels. In the event of a change in control of MPLX LP, unvested performance units will vest and be paid out based on 1) the TUR portion of the unvested performance units will be calculated using actual TUR performance amongst its specified peer group for the period from the date of grant to the date of the change in control, and target TUR performance for the period from the date of the

change in control to the end of the performance cycle and 2) the DCF-per-MPLX-LP-common-unit portion will be calculated at target. If an NEO terminates employment under any other circumstance, unvested performance units are forfeited.

### Outstanding Equity Awards at 2017 Fiscal Year-End

The following table provides information regarding unvested MPLX LP phantom units, unvested MPLX LP performance units, unvested MPC restricted stock, exercisable and unexercisable MPC stock options and unvested MPC performance units held by each of our NEOs as of December 31, 2017:

Name	Grant Date		Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options (#)	Option Exercise Price (\$)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested <sup>(3)</sup> (#)	Market Value of Shares or Units of Stock That Have Not Vested <sup>(4)</sup> (\$)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested <sup>(5)</sup> (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested <sup>(6)</sup> (\$)
Gary R. Heminger		MPLX LP					63,665	2,258,198	2,300,000	3,500,000
Pamela K.M. Beall		MPLX LP					14,628	518,855	552,500	892,500
	3/1/2016	MPC	5,684	11,368 <sup>(1)</sup>	34.63	3/1/2026	2,304	152,018	238,000	359,434
	3/1/2017	MPC		4,776 <sup>(2)</sup>	50.99	3/1/2027				
Michael J. Hennigan		MPLX LP					116,823	4,143,712		
		MPC					18,833	1,242,601		
C. Corwin Bromley		MPLX LP					66,706	2,366,062	300,000	600,000
	3/1/2017	MPC		4,214 <sup>(2)</sup>	50.99	3/1/2027	20,450	1,349,291	60,000	102,858
Gregory S. Floerke		MPLX LP					53,718	1,905,377	320,000	640,000
	3/1/2017	MPC		4,495 <sup>(2)</sup>	50.99	3/1/2027	20,489	1,351,864	64,000	109,715
Donald C. Templin		MPLX LP					51,424	1,824,009	1,950,000	3,150,000

- (1) This stock option grant is scheduled to become exercisable in one-third increments on the first, second and third anniversaries of the date of grant. This remaining unvested portion of the grant will become exercisable in one-half increments on March 1, 2018 and March 1, 2019.
- (2) This stock option is scheduled to become exercisable in one-third increments on the first, second and third anniversaries of the grant date—March 1, 2018, March 1, 2019 and March 1, 2020.
- (3) The amounts shown in this column reflect the number of unvested MPLX LP phantom units and MPC restricted stock held by each of our NEOs on December 31, 2017. Phantom unit and restricted stock grants generally are scheduled to vest in one-third increments on the first, second and third anniversaries of the grant date. The amounts shown in this column also include unvested shares of MPC restricted stock granted to Messrs. Bromley and Floerke as part of their retention grants that occurred at the time of the MarkWest Merger. These MPC restricted stock grants are scheduled to vest in full on the third anniversary of the grant date.

### MPLX LP Phantom Units

Name	Grant Date	Number of Unvested Units	Vesting Dates
Gary R. Heminger	3/1/2015	4,460	3/1/2018
	3/1/2016	27,642	3/1/2018, 3/1/2019
	3/1/2017	31,563	3/1/2018, 3/1/2019, 3/1/2020
		<b>63,665</b>	
Pamela K.M. Beall	3/1/2015	345	3/1/2018
	3/1/2016	5,340	3/1/2018, 3/1/2019
	3/1/2017	8,943	3/1/2018, 3/1/2019, 3/1/2020
		<b>14,628</b>	
Michael J. Hennigan	7/1/2017	46,729	7/1/2018, 7/1/2019, 7/1/2020
	7/1/2017	70,094	7/1/2020
		<b>116,823</b>	
C. Corwin Bromley	12/18/2015	50,240	Upon termination without cause
	12/18/2015	8,575	12/18/2018
	3/1/2017	7,891	3/1/2018, 3/1/2019, 3/1/2020
		<b>66,706</b>	
Gregory S. Floerke	12/18/2015	36,476	Upon termination without cause
	12/18/2015	8,825	12/18/2018
	3/1/2017	8,417	3/1/2018, 3/1/2019, 3/1/2020
		<b>53,718</b>	
Donald C. Templin	3/1/2015	1,014	3/1/2018
	3/1/2016	18,847	3/1/2018, 3/1/2019
	3/1/2017	31,563	3/1/2018, 3/1/2019, 3/1/2020
		<b>51,424</b>	

### MPC Restricted Stock

Name	Grant Date	Number of Unvested Shares	Vesting Dates
Pamela K.M. Beall	3/1/2016	1,637	3/1/2018, 3/1/2019
	3/1/2017	667	3/1/2018, 3/1/2019, 3/1/2020
		<b>2,304</b>	
Michael J. Hennigan	7/1/2017	7,533	7/1/2018, 7/1/2019, 7/1/2020
	7/1/2017	11,300	7/1/2020
		<b>18,833</b>	
C. Corwin Bromley	12/18/2015	19,861	12/18/2018
	3/1/2017	589	3/1/2018, 3/1/2019, 3/1/2020
		<b>20,450</b>	
Gregory S. Floerke	12/18/2015	19,861	12/18/2018
	3/1/2017	628	3/1/2018, 3/1/2019, 3/1/2020
		<b>20,489</b>	

- (4) The amounts shown in this column reflect the aggregate value of all unvested MPLX LP phantom units and MPC restricted stock held by each of our NEOs on December 31, 2017, using the December 29, 2017, MPLX LP common unit closing price of \$35.47 per unit and MPC closing price of \$65.98 per share. It also includes the value of unvested shares of MPC restricted stock granted to Messrs. Bromley and Floerke as part of their retention grants as discussed in the “Retention Agreements with Former MarkWest Executives”

section of our Annual Report on Form10-K for the year ended December 31, 2015. These are valued using the MPC closing price on December 29, 2017, of \$65.98 per share.

- (5) The amounts shown in this column reflect the number of unvested performance units held by each of our NEOs on December 31, 2017. Performance unit grants have a 36-month performance cycle and are designed to settle 25 percent in MPLX LP common units/MPC common stock and 75 percent in cash. Each of these performance unit grants has a target value of \$1.00 and payout may vary from \$0.00 to \$2.00 per unit. Payout for MPC performance unit awards made in 2016 and 2017 and MPLX performance unit awards made in 2016 is tied to our TUR/TSR as compared to specified peer groups. MPLX performance unit awards made in 2017 is tied to our TUR as compared to specified peer groups and a specified DCF-per-MPLX-LP-common-unit goal. Mr. Hennigan, who was not an employee on the dates these grants were made, does not have any unvested performance units.

#### MPLX LP Performance Units

<u>Name</u>	<u>Grant Date</u>	<u>Number of Unvested Units</u>	<u>Performance Period Ending Date</u>
Gary R. Heminger	3/1/2016	1,100,000	12/31/2018
	3/1/2017	1,200,000	12/31/2019
		<b>2,300,000</b>	
Pamela K.M. Beall	3/1/2016	212,500	12/31/2018
	3/1/2017	340,000	12/31/2019
		<b>552,500</b>	
C. Corwin Bromley	3/1/2017	300,000	12/31/2019
		<b>300,000</b>	
Gregory S. Floerke	3/1/2017	320,000	12/31/2019
		<b>320,000</b>	
Donald C. Templin	3/1/2016	750,000	12/31/2018
	3/1/2017	1,200,000	12/31/2019
		<b>1,950,000</b>	

#### MPC Performance Units

<u>Name</u>	<u>Grant Date</u>	<u>Number of Unvested Units</u>	<u>Performance Period Ending Date</u>
Pamela K.M. Beall	3/1/2016	170,000	12/31/2018
	3/1/2017	68,000	12/31/2019
		<b>238,000</b>	
C. Corwin Bromley	3/1/2017	60,000	12/31/2019
		<b>60,000</b>	
Gregory S. Floerke	3/1/2017	64,000	12/31/2019
		<b>64,000</b>	

- (6) The amount shown in this column for MPC reflects the aggregate value of all performance units held by Ms. Beall and Messrs. Floerke and Bromley on December 31, 2017, assuming a payout of \$1.4286 per unit for the March 1, 2016, grant and \$1.7143 per unit for the March 1, 2017, grant, which is the next higher performance achievement that exceeds the performance for these grants' performance period that ended December 31, 2017. The amounts shown in this column for MPLX LP reflect the aggregate value of all performance units held by Ms. Beall and Messrs. Heminger, Floerke, Bromley and Templin on December 31, 2017, assuming a payout of \$1.0000 per unit for the March 1, 2016, grant and \$2.0000 per

unit for the March 1, 2017, grant, which is the next higher performance achievement that exceeds the performance for these grants' performance period that ended December 31, 2017. Mr. Hennigan, who was not an employee on the dates these grants were made, does not have any unvested performance units.

### Option Exercises and Units Vested in 2017

The following table provides information regarding phantom units and MPC restricted stock that vested in 2017:

Name		Stock Awards	
		Number of Units/Shares Acquired on Vesting (#)	Value Realized on Vesting <sup>(1)</sup> (\$)
Gary R. Heminger	MPLX LP	25,121	951,332
Pamela K.M. Beall	MPLX LP	3,597	136,218
	MPC	2,798	141,971
C. Corwin Bromley	MPLX LP	8,574	311,579
Gregory S. Floerke	MPLX LP	8,825	320,701
Donald C. Templin	MPLX LP	11,942	452,244

- (1) This column reflects the actual pre-tax gain realized upon vesting of phantom units and restricted stock, which is the fair market value of the units or stock on the date of vesting.

### Post-Employment Benefits for 2017

#### Pension Benefits

MPC provides tax-qualified retirement benefits to its employees, including our NEOs, under the Marathon Petroleum Retirement Plan. In addition, MPC sponsors the Marathon Petroleum Excess Benefit Plan for the benefit of a select group of management and other employees who are "highly compensated" as defined by Section 414(q) of the Internal Revenue Code (annual compensation of \$120,000 or more in 2017).

#### 2017 Pension Benefits Table

Name	Plan Name	Number of Years of Credited Service <sup>(1)</sup>	Present Value of Accumulated Benefit <sup>(2)</sup> (\$)	Payments During Last Fiscal Year (\$)
Pamela K.M. Beall	Marathon Petroleum Retirement Plan	15.67 years	791,415	—
	Marathon Petroleum Excess Benefit Plan	15.67 years	1,519,789	—
Michael J. Hennigan	Marathon Petroleum Retirement Plan	0.58 years	23,826	—
	Marathon Petroleum Excess Benefit Plan	0.58 years	102,496	—
C. Corwin Bromley	Marathon Petroleum Retirement Plan	2.0 years	59,249	—
	Marathon Petroleum Excess Benefit Plan	2.0 years	135,683	—
Gregory S. Floerke	Marathon Petroleum Retirement Plan	2.0 years	46,827	—
	Marathon Petroleum Excess Benefit Plan	2.0 years	94,770	—
Donald C. Templin	Marathon Petroleum Retirement Plan	6.5 years	74,709	—
	Marathon Petroleum Excess Benefit Plan	6.5 years	474,653	—

- (1) The number of years of credited service shown in this column represents the number of years the NEO has participated in the plan. However, plan participation service used for the purpose of calculating each participant's benefit under the Marathon Petroleum Retirement Plan legacy final average pay formula was frozen as of December 31, 2009.
- (2) The present value of accumulated benefit for the Marathon Petroleum Retirement Plan was calculated assuming a discount rate of 3.55 percent, the RP2000 mortality table for lump sums, a 96 percent lump sum

election rate and retirement at age 62 (or current age, if later). In accordance with the Marathon Petroleum Retirement Plan provisions and actuarial assumptions, the discount rate for lump sum calculations is 0.75 percent for all anticipated years of retirement.

The 2017 Pension Benefits Table below reflects the actuarial present value of accumulated benefits payable to each of our NEOs under the Marathon Petroleum Retirement Plan and the defined benefit portion of the excess plans as of December 31, 2017. These values have been determined using actuarial assumptions consistent with those used in MPC's financial statements.

## Marathon Petroleum Retirement Plans

### *Marathon Petroleum Retirement Plan*

In general, our NEOs are immediately eligible to participate in the Marathon Petroleum Retirement Plan. The Marathon Petroleum Retirement Plan is primarily designed to provide participants with income after retirement. Prior to January 1, 2010, the monthly benefit under the Marathon Petroleum Retirement Plan was equal to the following formula:

$$\left[ 1.6\% \times \frac{\text{Final Average Pay}}{\text{Years of Participation}} \right] - \left[ 1.33\% \times \frac{\text{Estimated Primary Social Security Benefit}}{\text{Years of Participation}} \right]$$

This formula is referred to as the Marathon legacy benefit formula. Effective January 1, 2010, the Marathon legacy benefit formula was amended to (i) cease future accruals of additional years of participation, and (ii) as applied to eligible NEOs, cease further compensation updates. No more than 37.5 years of participation may be recognized under the Marathon legacy benefit formula.

Eligible earnings under the Marathon Petroleum Retirement Plan include, but are not limited to, pay for hours worked, pay for allowed hours, military leave allowance, commissions, 401(k) contributions to the Marathon Petroleum Thrift Plan and incentive compensation bonuses. Age continues to be updated under the Marathon legacy benefit formula.

Benefit accruals for years beginning in 2010 are determined under a cash-balance formula. Under the cash-balance formula, each year plan participants receive pay credits equal to a percentage of compensation based on their plan points. Plan points equal the sum of a participant's age and cash-balance service:

- Participants with less than 50 points receive a seven percent pay credit;
- Participants with at least 50 but less than 70 points receive a nine percent pay credit; and
- Participants with 70 or more points receive an 11 percent pay credit.

Participants in the Marathon Petroleum Retirement Plan become fully vested upon the completion of three years of vesting service. Normal retirement age for both the Marathon legacy benefit and cash-balance formulas is 65. However, retirement-eligible participants are able to retire and receive an unreduced benefit under the Marathon legacy benefit formula after reaching age 62.

The forms of benefit available under the Marathon Petroleum Retirement Plan include various annuity options and a lump sum distribution option.



Participants are eligible for early retirement upon reaching age 50 and completing 10 years of vesting service. If an employee retires between the ages of 50 and 62 with sufficient vesting service, the amount of benefit under the Marathon legacy benefit formula is reduced in accordance with the table below:

Age at Retirement	Early Retirement Factor	Age at Retirement	Early Retirement Factor
62	100%	55	75%
61	97%	54	71%
60	94%	53	67%
59	91%	52	63%
58	87%	51	59%
57	83%	50	55%
56	79%		

There are no early retirement subsidies under the cash-balance formula. Of our NEOs providing a majority of their services to our business, only Ms. Beall has accrued a benefit under the Marathon legacy benefit formula. Ms. Beall is currently eligible for early retirement benefits under the Marathon legacy benefit formula.

Under the cash-balance formula, plan participants receive pay credits based on age and cash-balance service. For 2017, Ms. Beall and Mr. Bromley received pay credits equal to 11 percent of compensation, which is the highest level of pay credit available under the plan. Messrs. Hennigan, Floerke and Templin received pay credits equal to nine percent of compensation. Additionally, under the terms of his employment offer entered into with MPC's former parent company Marathon Oil Company, Mr. Templin receives additional contributions to the non-qualified plan to ensure that the aggregate contributions from the qualified and non-qualified retirement plans equal 11 percent of his applicable compensation. Based on the age and service calculation specified in the Marathon Petroleum Retirement Plan, Mr. Templin will receive a supplemental non-qualified contribution set at 2 percent of eligible compensation in the Marathon Petroleum Excess Benefit Plan. This supplemental contribution will be eliminated when Mr. Templin becomes eligible for the full 11 percent contribution under the qualified plan in 2022.

#### ***Marathon Petroleum Excess Benefit Plan (Defined Benefit)***

Marathon Petroleum Company LP (or MPC LP) sponsors the Marathon Petroleum Excess Benefit Plan, an unfunded, non-qualified retirement plan, for the benefit of a select group of management and highly compensated employees. The Marathon Petroleum Excess Benefit Plan generally provides benefits that participants, including our NEOs, would have otherwise received under the tax-qualified Marathon Petroleum Retirement Plan were it not for Internal Revenue Code limitations. For our NEOs, eligible earnings under the Marathon Petroleum Excess Benefit Plan include the items listed above, excluding bonuses, for the Marathon Petroleum Retirement Plan, as well as deferred compensation contributions, for the highest consecutive 36-month period over the 10-year period up to December 31, 2012. The Marathon Petroleum Excess Benefit Plan also provides an enhancement for executive officers using the three highest bonuses earned over the 10-year period up to December 31, 2012, instead of the consecutive bonus formula in place for non-officers. MPC believes this enhancement is appropriate in light of the greater volatility of executive officer bonuses. However, as Messrs. Hennigan, Bromley and Floerke have not accrued a benefit under the Marathon legacy benefit formula, they are not eligible for this enhancement.

#### ***Marathon Petroleum Thrift Plan***

MPC LP sponsors the Marathon Petroleum Thrift Plan, a tax-qualified employee savings plan. In general, all of MPC's employees, including our NEOs, are immediately eligible to participate in the Marathon Petroleum Thrift Plan. The purpose of the Marathon Petroleum Thrift Plan is to assist employees in maintaining a steady program of savings to supplement their retirement income and to meet other financial needs.

The Marathon Petroleum Thrift Plan allows contributions for NEOs on a pre-tax or Roth basis. Employees may elect to make any combination of pre-tax or Roth contributions from one percent to a maximum of 75 percent of gross pay. The participating employer will match participant contributions at a rate of 117 percent up to a maximum of six percent of gross pay. All matching contributions made are fully vested.

***Marathon Petroleum Excess Benefit Plan (Defined Contribution)***

Certain highly compensated non-officer employees and, prior to January 1, 2006, executive officers who elected not to participate in the Marathon Petroleum Deferred Compensation Plan, comprise those eligible to receive defined contribution accruals under the Marathon Petroleum Excess Benefit Plan. The defined contribution formula in the Marathon Petroleum Excess Benefit Plan is designed to allow eligible employees to receive employer matching contributions equal to the amount they would have otherwise received under the tax-qualified Marathon Petroleum Thrift Plan were it not for Internal Revenue Code limitations.

Defined contribution accruals in the Marathon Petroleum Excess Benefit Plan are credited with interest equal to that paid in the “Marathon Stable Value Fund” option of the Marathon Petroleum Thrift Plan. The annual rate of return on this option for the year ended December 31, 2017, was 1.71 percent. All distributions from the plan are paid in the form of a lump sum following the participant’s separation from service.

As noted, our NEOs no longer participate in the defined contribution formula of the Marathon Petroleum Excess Benefit Plan; all non-qualified employer matching contributions for our NEOs now accrue under the Marathon Petroleum Amended and Restated Deferred Compensation Plan.

**Other Non-Qualified Deferred Compensation**

The Non-Qualified Deferred Compensation table below provides information regarding the non-qualified savings and deferred compensation plans sponsored by MPC or its subsidiaries:

**2017 Non-Qualified Deferred Compensation**

Name	Executive contributions in last fiscal year (\$)	Registrant contributions in last fiscal year <sup>(1)</sup> (\$)	Aggregate earnings in last fiscal year (\$)	Aggregate withdrawals/distributions (\$)	Aggregate balance at last fiscal year-end (\$)
Pamela K.M. Beall					
Marathon Petroleum Excess Benefit Plan	—	—	2,880	—	135,932
Marathon Petroleum Deferred Compensation Plan	—	53,838	121,391	—	901,206
Michael J. Hennigan					
Marathon Petroleum Deferred Compensation Plan	280,000	79,326	34,667	—	393,993
C. Corwin Bromley					
Marathon Petroleum Deferred Compensation Plan	9,300	45,279	11,758	—	108,503
Gregory S. Floerke					
Marathon Petroleum Deferred Compensation Plan	—	41,864	14,270	—	91,488
Donald C. Templin					
Marathon Petroleum Deferred Compensation Plan	—	59,293	48,440	—	380,728

<sup>(1)</sup> The amounts shown in this column are also included in the “All Other Compensation” column of the 2017 Summary Compensation Table.

**Marathon Petroleum Deferred Compensation Plan**

MPC LP sponsors the Marathon Petroleum Amended and Restated Deferred Compensation Plan (which we refer to as the Marathon Petroleum Deferred Compensation Plan). The Marathon Petroleum Deferred Compensation

Plan is an unfunded, non-qualified plan in which our NEOs may participate. This plan is designed to provide participants the opportunity to supplement their retirement savings by deferring income in a tax-effective manner. Participants may defer up to 20 percent of their salary and bonus each year. Deferral elections are made in December of each year for amounts to be earned in the following year and are irrevocable. The Marathon Petroleum Deferred Compensation Plan provides for a match on any participant's salary and bonus deferral equal to the percentage provided by the Marathon Petroleum Thrift Plan, which is currently 117 percent of contributions up to six percent of gross pay. Participants are fully vested in their deferrals under the plan.

In addition, the Marathon Petroleum Deferred Compensation Plan provides benefits for participants equal to the employer matching contributions they would have otherwise received under the tax-qualified Marathon Petroleum Thrift Plan were it not for Internal Revenue Code limitations. All matching contributions made on or after January 1, 2016, are fully vested.

The investment options available under the Marathon Petroleum Deferred Compensation Plan generally mirror the investment options offered to participants under the Marathon Petroleum Thrift Plan with the exception of MPC common stock and BrokerageLink, which are not investment options under the Marathon Petroleum Deferred Compensation Plan. The Marathon Petroleum Deferred Compensation Plan provides that all participants will receive their benefits as a lump sum following separation from service.

### **Section 409A Compliance**

All of MPC's non-qualified deferred compensation plans in which our NEOs participate are intended to comply with, or be exempt from, Section 409A of the Internal Revenue Code. As a result, distribution of amounts subject to Section 409A may be delayed for six months following retirement or other separation from service where the participant is considered a "specified employee" for purposes of Section 409A.

### **Potential Payments Upon a Termination or Change In Control**

We have adopted the MPLX LP Executive Change in Control Severance Benefits Plan (the "MPLX CIC Plan"), which provides certain benefits upon a change in control of MPLX and a Qualified Termination and is designed to ensure continuity of management through a change-in-control transaction. For purposes of the MPLX CIC Plan, a Qualified Termination is one where an NEO separates from service in connection with or within two years after the date of a change in control of MPLX unless such separation from service is:

- due to death or disability;
- for cause;
- effected by the employee other than for good reason, being defined as a reduction in the NEO's roles, responsibilities, pay or benefits, or the NEO being required to relocate more than 50 miles from his or her current location; or
- on or after the date the employee attains age 65.

NEOs who receive an offer for comparable employment from an acquirer or successor entity in the change in control will not be eligible to receive benefits under the MPLX CIC Plan.

In the event of a Qualified Termination, our NEOs and other executives officers are eligible to receive:

- a cash payment of up to three times the sum of the NEO's current annualized base salary plus three times the highest bonus paid in the three years before the termination or change in control;
- life and health insurance benefits for up to 36 months after termination at the active employee cost
- an additional three years of service credit and three years of age credit for purposes of retiree health and life insurance benefits;

- a cash payment equal to the actuarial equivalent of the difference between amounts receivable by the NEO under the final average pay formula in MPC's pension plans and those which would be payable if: the NEO had an additional three years of participation service credit; the NEO's final average pay would be the higher of their salary at the time of the change-in-control event or termination plus their highest annual bonus from the preceding three years; for purposes of determining early retirement commencement factors, the NEO is credited with three additional years of vesting service credit and three additional years of age; and the NEO's pension had been fully vested; and
- a cash payment equal to the difference between amounts receivable under MPC's defined contribution plans and amounts which would have been received if the NEO's defined contribution plan account had been fully vested.

The MPLX CIC Plan also provides that NEOs who incur a Qualified Termination in connection with a change in control of MPLX or who separate from service with MPLX as a result of the change in control transaction (i.e., where the NEO remains employed with MPC but no longer provides services to MPLX) will become fully vested in all outstanding MPLX LTI awards. With respect to outstanding MPLX performance units, the portion of the award attributable to the pre-change in control period would vest based on actual performance during such period and the portion attributable to the post-change in control period would vest at the target level. In addition, if an NEO incurs a Qualified termination in connection with a change in control of MPLX or separates from service with MPC as a result of the change in control transaction (i.e., where the NEO commences employment with the acquirer or successor entity in the transaction and terminates employment with MPC), the NEO will become fully vested in all outstanding MPC LTI awards, provided that performance based awards remain subject to the attainment of the applicable performance goals at the end of the regularly scheduled performance period.

The table below reflects the amount of compensation payable to each of our NEOs if a termination occurred on December 31, 2017. The table reflects only those termination scenarios for each NEO that would trigger a separation payment, including a change in control and a Qualified Termination. The table uses our closing common unit price on December 29, 2017, the last day of trading of the year.

Mr. Bromley retired effective January 1, 2018.

## Potential Payments upon Termination or Termination in the Event of a Change in Control

Name	Scenario	Severance <sup>(1)</sup> (\$)	Additional Pension Benefits <sup>(2)</sup> (\$)	Accelerated Options <sup>(3)</sup> (\$)	Accelerated Restricted Stock <sup>(4)</sup> (\$)	Accelerated Performance Units <sup>(5)</sup> (\$)	Other Benefits <sup>(6)</sup> (\$)	Total (\$)
Gary R. Heminger	Change in Control (With Qualified Termination)	4,201,389	32,520,813	12,732,756	7,738,959	9,660,000	50,595	66,904,512
Pamela K. M. Beall	Change in Control (With Qualified Termination) <sup>(7)</sup>	3,225,000	2,053,085	529,354	729,727	790,500	41,442	7,369,108
	Voluntary Retirement	—	—	529,354	—	—	—	529,354
Michael J. Hennigan	Change in Control (With Qualified Termination) <sup>(7)</sup>	2,400,000	—	—	5,386,313	—	53,655	7,839,968
C. Corwin Bromley	Change in Control (With Qualified Termination) <sup>(7)</sup>	2,745,000	—	63,168	3,715,353	360,000	50,930	6,934,451
	Voluntary Retirement	—	—	63,168	—	—	—	63,168
	Involuntary Termination by Company Without Cause or Good Reason <sup>(8)</sup>	—	—	—	3,396,597	—	—	3,396,597
	Separation from Service Without Cause <sup>(9)</sup>	—	—	—	1,782,013	—	—	1,782,013
Gregory S. Floerke	Change in Control (With Qualified Termination) <sup>(7)</sup>	2,625,000	—	67,380	3,257,241	384,000	50,808	6,384,429
	Involuntary Termination by Company Without Cause or Good Reason <sup>(8)</sup>	—	—	—	2,917,255	—	—	2,917,255
	Separation from Service Without Cause <sup>(9)</sup>	—	—	—	1,293,804	—	—	1,293,804
Donald C. Templin	Change in Control (With Qualified Termination) <sup>(7)</sup>	6,600,000	—	—	1,824,009	1,950,000	54,469	10,428,478

(1) The payment of cash severance upon a change in control requires both (a) the occurrence of a change in control and (b) a qualified termination as specified in the MPLX's Executive Change in Control Severance Benefits Plan. If the Qualified Termination occurs within three years of the date the officer reaches age 65, the officer's benefit will be limited to a pro rata portion of the benefit. The officer's benefit is calculated using a fraction equal to the number of full and partial months existing between the Qualifying Termination and the officer's 65th birthday divided by 36 months.

Mr. Heminger's benefit has been reduced as he is within three years of reaching age 65.

(2) The incremental retirement benefits included in these amounts were calculated using the following assumptions: individual life expectancies using the RP2000 Combined Healthy Table weighted 75 percent male and 25 percent female; a discount rate of 1.00 percent for NEOs who are retirement eligible (taking into account the additional three years of age and service credit) and 1.00 percent for our NEOs who are not retirement eligible; the current lump-sum interest rate for the relevant plans; and a lump-sum form of benefit. Health and welfare plans reflect the incremental cost of coverage under the policy using the assumptions used for financial reporting purposes under generally accepted accounting principles in the U.S.

(3) The vesting of stock options is accelerated upon retirement or a change in control with a qualified termination. The amounts shown in this column reflect the value that would be realized if accelerated stock options were exercised on

December 31, 2017, taking into account the spread (if any) between the options' exercise prices and the closing price of MPC common stock on December 29, 2017.

- (4) The vesting of restricted stock is accelerated upon a change in control with a qualified termination. The amounts shown in this column reflect the value that would be realized if accelerated MPC restricted stock and MPLX phantom unit awards vested on December 31, 2017, taking into account the closing price of MPC common stock and MPLX LP common units on December 29, 2017.
- (5) The amounts shown in this column reflect the MPC and MPLX performance unit target vesting amounts that would be payable in the event of a change in control with each performance unit having a target value of \$1.00.
- (6) Other benefits include 36 months of continued health, dental and life insurance coverage in the event of a change in control.
- (7) The additional pension benefits due to a change in control and subsequent Qualified Termination is attributable solely to the final average pay formula in the Executive Change in Control Severance Benefits Plan. Given the date of hire for Messrs. Hennigan, Bromley, Floerke and Templin, they are not eligible for any benefit under this formula.
- (8) If either of Messrs. Bromley or Floerke separate from service as a result of a forced relocation of his principal place of employment to a location more than 50 miles from his current principal place of employment, his unvested MPLX LP phantom units and MPC restricted stock received as part of his retention grants awarded in 2015 will vest and become payable.
- (9) If either of Messrs. Bromley or Floerke separate from service without cause, the separated NEO is entitled to a portion of the grant of MPLX LP phantom units received as part of his retention grants awarded in 2015.

## COMPENSATION OF OUR DIRECTORS

The officers or employees of our general partner or of MPC who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not officers or employees of our general partner or of MPC receive compensation as “non-management directors.”

In October 2016, the board of directors of our general partner approved an increase to the non-management director compensation package. Effective January 1, 2017, each of our non-management directors receives a compensation package having an annual value equal to \$175,000, instead of the prior \$150,000, and payable as follows:

- 50 percent in the form of a cash retainer, payable in equal quarterly installments of \$21,875 (at the commencement of each calendar quarter); and
- 50 percent in the form of a phantom unit award (granted at the commencement of each calendar quarter) representing a number of units having a value (based on the closing price of our common units on the date of grant) equal to \$21,875. The phantom unit awards are not subject to any risk of forfeiture once granted and are automatically deferred until and settled in common units at the time the non-management director separates from service on the board or upon his or her death, if earlier.

In addition, the chair of each standing committee of the board and our lead director, who also serves on the executive committee of the board, each receive an additional annual retainer. These additional annual retainers are payable in cash (in equal quarterly installments at the commencement of each calendar quarter) as follows:

- Audit Committee Chair—\$15,000;
- Conflicts Committee Chair—\$15,000;
- Lead Director & Executive Committee Member—\$15,000; and
- Other Committee Chair—\$7,500.

Members of the conflicts committee will also receive a meeting fee in the amount of \$1,500 per meeting for each conflicts committee meeting such member attends in a calendar year in excess of six meetings.

Further, each director is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law and is reimbursed for all expenses incurred in attending to his or her duties as a director.

## 2017 Director Compensation Table

Amounts reflected in the table below represent compensation earned by or paid to our general partner's non-employee directors for the year ended December 31, 2017:

Name	Fees Earned or Paid in Cash <sup>(1)</sup> (\$)	Unit Awards <sup>(2)</sup> (\$)	Option Awards (\$)	Non-Equity Incentive Plan Compensation (\$)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings (\$)	All Other Compensation <sup>(3)</sup> (\$)	Total (\$)
Michael L. Beatty	159,500	87,500	—	—	—	—	247,000
David A. Daberko	87,500	87,500	—	—	—	—	175,000
Christopher A. Helms	174,500	87,500	—	—	—	10,000	272,000
Garry L. Peiffer	100,042	87,500	—	—	—	1,000	188,542
Dan D. Sandman	167,000	87,500	—	—	—	5,000	259,500
Frank M. Semple	87,500	87,500	—	—	—	—	175,000
John P. Surma	87,500	87,500	—	—	—	—	175,000
C. Richard Wilson <sup>(4)</sup>	164,750	87,500	—	—	—	—	252,250

- (1) The amounts shown in this column reflect the director cash retainers, conflicts committee meeting fees and committee chair and lead director fees earned or paid for service from January 1, 2017, through December 31, 2017. The amounts shown for Messrs. Peiffer and Wilson reflect a prorated audit committee chair fee.
- (2) The amounts shown in this column reflect the aggregate grant date fair value, as computed in accordance with provisions of Financial Accounting Standards Board Accounting Standards Codification 718, Compensation—Stock Compensation (“FASB ASC Topic 718”), for phantom unit awards granted to the non-management directors in 2017. All phantom unit awards are deferred until departure from the board and distribution equivalents in the form of additional phantom unit awards are credited to non-management director deferred accounts as and when distributions are paid on our common units. The aggregate number of MPLX LP phantom unit awards credited for board service and outstanding as of December 31, 2017, for each non-employee director is as follows: Messrs. Daberko, Helms, Sandman, Surma, and Wilson, 10,617; Mr. Peiffer, 7,982; Mr. Beatty, 5,307; and Mr. Semple, 2,970.
- (3) The amounts shown in this column reflect contributions made on behalf of Messrs. Helms, Peiffer and Sandman to educational institutions under our matching gifts program.
- (4) Mr. Wilson retired from the board of directors of our general partner pursuant to our mandatory retirement policy effective December 31, 2017.

## Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

### Security Ownership of Certain Beneficial Owners

The following table sets forth information from filings made with the SEC as to each person or group who, as of December 31, 2017 (unless otherwise noted), beneficially owned more than five percent of our outstanding units or more than five percent of any class of our outstanding units:

Name and Address of Beneficial Owner	Number of Common Units Representing Limited Partner Interests	Percent of Common Units Representing Limited Partner Interests	Number of General Partner Units	Percent of General Partner Units	Percent of Units Representing Total Partnership Interests
Marathon Petroleum Corporation <sup>(1)</sup> 539 S. Main Street Findlay, Ohio 45840	118,090,823	29.0%	8,308,773	100%	30.4%
Tortoise Capital Advisors, L.L.C. <sup>(2)</sup> 11550 Ash Street, Suite 300 Leawood, Kansas 66211	24,236,080 <sup>(2)</sup>	5.6% <sup>(2)</sup>	—	—	5.8%
ALPS Advisors, Inc. <sup>(3)</sup> 1290 Broadway, Suite 1100 Denver, Colorado 80203	23,994,554 <sup>(3)</sup>	5.9% <sup>(3)</sup>	—	—	5.8%
Alerian MLP ETF <sup>(3)</sup> 1290 Broadway, Suite 1100 Denver, Colorado 80203	23,771,609 <sup>(3)</sup>	5.8% <sup>(3)</sup>	—	—	5.7%

- (1) The 118,090,823 common units representing limited partner interests (“MPLX LP common units”) are directly held by MPLX Logistics Holdings LLC, MPLX Holdings Inc. and MPLX GP LLC. The 8,308,773 general partner units are directly held by MPLX GP LLC and represent its two percent general partner interest in MPLX LP. Marathon Petroleum Corporation is the ultimate parent company of MPLX GP LLC, MPLX Logistics Holdings LLC and MPLX Holdings Inc. and may be deemed to beneficially own the MPLX LP common units directly held by MPLX GP LLC, MPLX Logistics Holdings LLC and MPLX Holdings Inc., and the general partner units directly held by MPLX GP LLC. MPC Investment LLC owns all of the membership interests in or shares of MPLX GP LLC, MPLX Logistics Holdings LLC and MPLX Holdings Inc., and MPC owns all of the membership interests in MPC Investment LLC.
- (2) According to a Schedule 13G/A filed with the SEC on February 13, 2018, by Tortoise Capital Advisors, L.L.C. (“TCA”). According to such Schedule 13G/A, TCA acts as an investment adviser to certain investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners under Rule 13d-3 of the Act, of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA has reported that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment adviser to certain managed accounts. Under contractual agreements with these managed account clients, TCA, with respect to the securities held in these client accounts, has investment and voting power with respect to certain of these client accounts, and has investment power but no voting power with respect to certain other of these client accounts. TCA has reported that it shares voting and/or investment power over the securities held by these client managed accounts despite a delegation of voting and/or investment power to TCA because the clients have the right



to acquire investment and voting power through termination of their agreements with TCA. TCA may be deemed the beneficial owner of the securities covered by this statement under Rule 13d-3 of the Act that are held by its clients. Subject to the above, TCA reported that it has beneficial ownership of 24,236,080 MPLX LP common units or 5.6 percent of the MPLX LP common units outstanding, sole voting power over 559,771 of our MPLX LP common units, shared voting power over 20,579,794 of our MPLX LP common units, sole dispositive power over 559,771 of our MPLX LP common units and shared dispositive power over 23,676,309 of our MPLX LP common units.

- (3) According to a Schedule 13G/A filed with the SEC on February 6, 2018, by ALPS Advisors, Inc. (“AAI”) and Alerian MLP ETF. According to such Schedule 13G/A, AAI, an investment adviser registered under Section 203 of the Investment Advisors Act of 1940, furnishes investment advice to investment companies registered under the Investment Company Act of 1940 (collectively referred to as the “Funds”). In its role as investment advisor, AAI has voting and/or investment power over the securities of the Issuer that are owned by the Funds, and may be deemed to be the beneficial owner of the shares of the Issuer held by the Funds. However, all securities reported in this schedule are owned by the Funds. AAI disclaims beneficial ownership of such securities. In addition, the filing of this Schedule 13G/A shall not be construed as an admission that the reporting person or any of its affiliates is the beneficial owner of any securities covered by this Schedule 13G/A for any other purposes than Section 13(d) of the Securities Exchange Act of 1934. Alerian MLP ETF is an investment company registered under the Investment Company Act of 1940 and is one of the Funds to which AAI provides investment advice. Subject to the above, AAI reported that it has beneficial ownership of 23,994,554 MPLX LP common units or 5.90 percent of the MPLX LP common units outstanding, sole voting power over none of our MPLX LP common units, shared voting power over 23,994,554 of our MPLX LP common units, sole dispositive power over none of our MPLX LP common units and shared dispositive power over 23,994,554 of our MPLX LP common units. Subject to the above, and according to the Schedule 13G/A, Alerian MLP ETF reported that it has beneficial ownership of 23,771,609 MPLX LP common units or 5.84 percent of the MPLX LP common units outstanding, sole voting power over none of our MPLX LP common units, shared voting power over 23,771,609 of our MPLX LP common units, sole dispositive power over none of our MPLX LP common units and shared dispositive power over 23,771,609 of our MPLX LP common units.

## Security Ownership of Directors and Executive Officers

The following table sets forth the number of MPLX LP common units beneficially owned as of January 31, 2018, except as otherwise noted, by each director of our general partner, by each named executive officer of our general partner and by all directors and executive officers of our general partner as a group. The address for each person named below is c/o MPLX LP, 200 East Hardin Street, Findlay, Ohio 45840.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership <sup>(1)</sup>	Percent of Total Outstanding
<b>Directors / Named Executive Officers</b>		
Gary R. Heminger	206,186 <sup>(2)(5)(6)(7)</sup>	*
Pamela K.M. Beall	29,410 <sup>(2)(5)(7)</sup>	*
Michael L. Beatty	33,284 <sup>(2)(4)</sup>	*
C. Corwin Bromley	56,072 <sup>(2)(5)</sup>	*
David A. Daberko	23,433 <sup>(2)(3)(4)</sup>	*
Gregory S. Floerke	74,774 <sup>(2)(5)</sup>	*
Timothy T. Griffith	23,752 <sup>(2)(5)(7)</sup>	*
Christopher A. Helms	22,223 <sup>(2)(4)</sup>	*
Michael J. Hennigan	116,823 <sup>(5)</sup>	*
Garry L. Peiffer	40,286 <sup>(4)(6)</sup>	*
Dan D. Sandman	55,223 <sup>(2)(4)</sup>	*
Frank M. Semple	580,495 <sup>(2)(3)(4)(6)</sup>	*
John P. Surma	20,933 <sup>(2)(3)(4)</sup>	*
Donald C. Templin	84,154 <sup>(2)(5)(7)</sup>	*
<b>All Directors and Executive Officers as a group (17 reporting persons)</b>	1,396,119 <sup>(2)(3)(4)(5)(6)(7)</sup>	*

- (1) None of the common units reported in this column are pledged as security.
- (2) Includes common units directly or indirectly held in beneficial form.
- (3) Includes phantom unit awards granted pursuant to the MPLX LP 2012 Incentive Compensation Plan and credited within a deferred account pursuant to the Marathon Petroleum Corporation Deferred Compensation Plan for Non-Employee Directors. The aggregate number of phantom unit awards credited as of January 31, 2018, for each of Messrs. Daberko and Surma is 2,210; and Mr. Semple 624.
- (4) Includes phantom unit awards granted pursuant to the MPLX LP 2012 Incentive Compensation Plan and credited within a deferred account pursuant to the MPLX GP LLC Amended and Restated Non-Management Director Compensation Policy and Director Equity Award Terms. The aggregate number of phantom unit awards credited as of January 31, 2018, for the non-management directors of our general partner is as follows: Messrs. Daberko, Helms, Sandman and Surma, 11,223 each; Mr. Beatty, 5,914; Mr. Peiffer, 8,589; and Mr. Semple, 3,577.
- (5) Includes phantom unit awards granted pursuant to the MPLX LP 2012 Incentive Compensation Plan, which may be forfeited under certain conditions.
- (6) Includes common units indirectly beneficially owned in trust. The number of common units held in trust as of January 31, 2018, by each applicable director or named executive officer of our general partner is as follows: Mr. Heminger, 35,750; Mr. Peiffer, 31,697; and Mr. Semple, 527,517.
- (7) Includes common units issued in settlement of performance units within sixty days of January 31, 2018.
- \* The percentage of common units beneficially owned by each director or each executive officer of our general partner does not exceed one percent of the common units outstanding, and the percentage of common units beneficially owned by all directors and executive officers of our general partner as a group does not exceed one percent of the common units outstanding.

The following table sets forth the number of shares of MPC common stock beneficially owned as of January 31, 2018, except as otherwise noted, by each director of our general partner, by each named executive officer of our

general partner and by all directors and executive officers of our general partner as a group. The address for each person named below is c/o MPLX LP, 200 East Hardin Street, Findlay, Ohio 45840.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership <sup>(1)</sup>	Percent of Total Outstanding
<b>Directors/Named Executive Officers</b>		
Gary R. Heminger	2,859,765 <sup>(2)(4)(5)(7)(8)(9)</sup>	*
Pamela K.M. Beall	113,539 <sup>(2)(4)(8)(9)</sup>	*
Michael L. Beatty	—	*
C. Corwin Bromley	16,922 <sup>(2)(8)</sup>	*
David A. Daberko	151,356 <sup>(2)(3)</sup>	*
Gregory S. Floerke	22,151 <sup>(4)(5)(8)</sup>	*
Timothy T. Griffith	221,662 <sup>(2)(4)(8)(9)</sup>	*
Christopher A. Helms	—	*
Michael J. Hennigan	18,833 <sup>(4)</sup>	*
Garry L. Peiffer	63,394 <sup>(7)</sup>	*
Dan D. Sandman	—	*
Frank M. Semple	3,646 <sup>(3)</sup>	*
John P. Surma	40,578 <sup>(3)(7)</sup>	*
Donald C. Templin	528,677 <sup>(2)(4)(8)(9)</sup>	*
<b>All Directors and Executive Officers as a group (17 reporting persons)</b>	<b>4,342,006<sup>(2)(3)(4)(5)(6)(7)(8)(9)</sup></b>	<b>*</b>

- (1) None of the shares of common stock reported in this column are pledged as security.
- (2) Includes shares of common stock directly or indirectly held in registered or beneficial form.
- (3) Includes restricted stock unit awards granted pursuant to the Second Amended and Restated Marathon Petroleum Corporation 2011 Incentive Compensation Plan and/or the Marathon Petroleum Corporation 2012 Incentive Compensation Plan, and credited within a deferred account pursuant to the Marathon Petroleum Corporation Deferred Compensation Plan for Non-Employee Directors. The aggregate number of restricted stock unit awards credited as of January 31, 2018, is as follows: Mr. Daberko, 147,356; Mr. Semple, 3,646; and Mr. Surma, 30,578.
- (4) Includes shares of restricted stock issued pursuant to the Marathon Petroleum Corporation 2012 Incentive Compensation Plan, which are subject to limits on sale and transfer, and may be forfeited under certain conditions.
- (5) Includes shares of common stock held within the Marathon Petroleum Thrift Plan.
- (6) Includes shares of common stock held within the Marathon Petroleum Corporation Dividend Reinvestment and Direct Stock Purchase Plan.
- (7) Includes shares of common stock indirectly beneficially owned in trust. The number of shares held in trust as of January 31, 2018, by each applicable director or named executive officer of our general partner is as follows: Mr. Heminger, 21,228; Mr. Peiffer, 63,394; and Mr. Surma, 10,000.
- (8) Includes stock options exercisable within sixty days of January 31, 2018.
- (9) Includes shares of common stock issued in settlement of performance units within sixty days of January 31, 2018.
- \* The percentage of shares beneficially owned by each director or each executive officer of our general partner does not exceed one percent of the MPC common shares outstanding, and the percentage of shares beneficially owned by all directors and executive officers of our general partner as a group does not exceed one percent of the MPC common shares outstanding.

## Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2017, with respect to common units that may be issued under the MPLX LP 2012 Incentive Compensation Plan:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights <sup>(1)</sup>	Weighted average exercise price of outstanding options, warrants and rights <sup>(2)</sup>	Number of securities remaining available for future issuance under equity compensation plans <sup>(3)</sup>
Equity compensation plans approved by security holders	1,494,551	N/A	586,637
Equity compensation plans not approved by security holders	—	—	—
Total	1,494,551		586,637

(1) Includes the following:

- (a) 1,351,523 phantom unit awards granted pursuant to the MPLX 2012 Plan for common units unissued and not forfeited, cancelled or expired as of December 31, 2017.
- (b) 143,028 units as the maximum potential number of common units that could be issued in settlement of performance units outstanding as of December 31, 2017, pursuant to the MPLX 2012 Plan based on the closing price of our common units on December 29, 2017, of \$35.47 per unit. The number of units reported for this award vehicle may overstate dilution. See Item 8. Financial Statements and Supplementary Data—Note 20 for more information on performance unit awards granted under the MPLX 2012 Plan.

(2) There is no exercise price associated with phantom unit awards.

(3) Reflects the common units available for issuance pursuant to the MPLX 2012 Plan. The number of units reported in this column assumes 143,028 as the maximum potential number of common units that could be issued in settlement of performance units outstanding as of December 31, 2017, pursuant to the MPLX 2012 Plan based on the closing price of our common units on December 29, 2017, of \$35.47 per unit. The number of units assumed for this award vehicle may understate the number of common units available for issuance pursuant to the MPLX 2012 Plan. See Item 8. Financial Statements and Supplementary Data—Note 20 for more information on performance unit awards issued pursuant to the MPLX 2012 Plan.

## Item 13. Certain Relationships and Related Transactions, and Director Independence

### Certain Relationships and Related Party Transactions

Our general partner is an affiliate of MPC. On March 1, 2017, we acquired certain pipeline, storage and terminal assets from MPC for \$1.5 billion in cash and a fixed number of common units and general partner units of 13.0 million and 0.3 million, respectively. The general partner units maintained MPC's two percent general partner economic interest. As of the acquisition date, the assets consisted of 174 miles of crude oil pipelines and 430 miles of refined products pipelines, nine butane and propane storage caverns located in Michigan with approximately 1.8 million barrels of NGL storage capacity, 59 terminals for the receipt, storage, blending, additization, handling and redelivery of refined petroleum products, along with one leased terminal and partial ownership interest in two terminals. Collectively, the 62 terminals had a combined total shell capacity of approximately 23.6 million barrels. The terminal facilities are located primarily in the Midwest, Gulf Coast and Southeast regions of the United States. MPC waived two-thirds of the first quarter 2017 distributions on MPLX LP common units issued in connection with this transaction. See Item 8. Financial Statements and Supplementary Data—Note 4 for more information on this transaction.

On September 1, 2017, we acquired joint-interest ownerships in certain pipelines and storage facilities from MPC for \$420 million in cash and a fixed number of common units and general partner units of 18.5 million and

0.4 million, respectively. The general partner units maintained MPC's two percent general partner economic interest. The acquired ownership interests included a 35 percent ownership interest in Illinois Extension, a 40.7 percent ownership interest in LOOP, a 58.52 percent ownership interest in LOCAP, and a 24.51 percent ownership interest in Explorer (collectively, the "Joint-Interest Acquisition"). As of the acquisition date, the assets held by these entities include a 1,830-mile refined products pipeline, storage facilities, pump stations, and a deepwater oil port, located offshore of Louisiana. The infrastructure serves primarily the Midwest and Gulf Coast regions of the United States. MPC waived approximately two-thirds of the third quarter 2017 distributions on MPLX LP common units issued in connection with this transaction. See Item 8. Financial Statements and Supplementary Data—Note 4 for more information on this transaction.

On November 13, 2017, we entered into a Membership Interests Contribution Agreement (the "November 2017 Contribution Agreement") with MPLX GP, MPLX Logistics, MPLX Holdings and MPC Investment, related to the acquisition of ownership interests in MPLX Fuels Distribution LLC and MPLX Refining Logistics LLC, entities indirectly held by MPC. Pursuant to the November Contribution Agreement, the consideration consisted of \$4.1 billion in cash and a fixed number of MPLX LP common units and MPLX LP general partner units of 111.6 million and 2.3 million, respectively. The general partner units maintained MPC's two percent general partner interest in the Partnership. The acquisition closed on February 1, 2018. MPC waived the fourth quarter 2017 distributions on the MPLX LP common units issued in connection with this transaction.

On December 15, 2017, we entered into a Partnership Interests Restructuring Agreement with MPLX GP (the "Partnership Interests Restructuring Agreement"), pursuant to which MPLX LP incentive distribution rights ("IDRs") held by MPLX GP would be eliminated and the two percent general partner interest in the Partnership held by MPLX GP would be converted into a non-economic general partner interest in MPLX LP in exchange for 275 million MPLX LP common units. Pursuant to the Partnership Interests Restructuring Agreement, the third amended and restated agreement of limited partnership would be amended to reflect the restructuring. The acquisition closed on February 1, 2018. The fourth amended and restated agreement of limited partnership was adopted on February 1, 2018. MPC agreed to cap fourth quarter 2017 distributions on the MPLX LP common units issued in connection with this transaction at the amount that would have been payable with respect to MPC's economic general partner interests as they existed immediately prior to the closing of this transaction.

As of February 16, 2018, MPC owned 504,701,934 common units. Our general partner manages our operations and activities through its officers and directors. In addition, Mr. Heminger, serves as an executive officer of our general partner and MPC. Accordingly, we view transactions between us and MPC as related party transactions.

#### ***Distributions by the Partnership***

Pursuant to our third amended and restated agreement of limited partnership, which was in effect during 2017, we made cash distributions to our unitholders, including MPC as the direct and indirect holder of common units, as well as a two percent general partner interest and all of our outstanding IDRs. As distributions exceeded the minimum quarterly distribution and target distribution levels, the general partner was entitled to receive increasing percentages of our distributions, up to 48 percent of our distributions above the highest target distribution level, on the IDRs. In 2017, we paid MPC \$212 million in cash distributions with respect to its common units, and \$286 million in cash distributions with respect to its two percent general partner interest and the IDRs. As of February 1, 2018, the IDRs were eliminated and the economic general partner interest was converted into a non-economic general partner interest. In addition, our agreement of limited partnership has been amended and restated. The fourth amended and restated agreement of limited partnership, which was adopted on February 1, 2018, provides for distributions of available cash, after payment of distributions on the Preferred units, to common unitholders pro rata.

#### ***Reimbursements paid to MPC***

Pursuant to our third amended and restated agreement of limited partnership, which was in effect during 2017, we are required to reimburse our general partner and its affiliates, including MPC, for all costs and expenses that

our general partner and its affiliates, including MPC, incur on our behalf for managing and controlling our business and operations. Except to the extent specified under the omnibus agreement (described below), our general partner determines the amount of these expenses and such determinations are required to be made in good faith in accordance with the terms of our third amended and restated agreement of limited partnership. In 2017, we reimbursed our general partner \$4 million for costs and expenses incurred on our behalf. Our fourth amended and restated agreement of limited partnership, which was adopted on February 1, 2018, contains similar provisions regarding reimbursements.

### ***Transactions and Commercial and Other Agreements with MPC***

We have multiple long-term, fee-based transportation and storage services agreements, as well as a variety of operating services agreements, management services agreements, licensing agreements, employee services agreements, an omnibus agreement, a loan agreement, and an aircraft time-sharing agreement with MPC and its consolidated subsidiaries. See “Our Transportation, Terminal, and Storage Services Agreements with MPC” and “Operating and Management Services Agreements with MPC” in Item 1 and Note 6—Related Party Agreements and Transactions in the Notes to Consolidated Financial Statements, for information regarding material related party activities with MPC.

### **Procedures for Review, Approval and Ratification of Related Person Transactions**

The board of directors of our general partner has adopted a formal written related person transactions policy. Under the policy, a “related person” includes any director, nominee for director, executive officer, or a known beneficial holder of more than five percent of any class of the Partnership’s voting securities (other than MPC or its affiliates) or any immediate family member of a director, nominee for director, executive officer or more than five percent owner. This procedure applies to any transaction, arrangement or relationship and any series of similar transactions, arrangements or relationships in which we are a participant and the amount involved exceeds \$120,000 and in which a related person has a direct or indirect material interest; provided that the following transactions, arrangements or relationships will be deemed to have standing pre-approval of the board of directors:

- Payment of compensation to an executive officer or director of our general partner if the compensation is otherwise required to be disclosed in our filings with the SEC;
- Any transaction where the related person’s interest arises solely from the ownership of securities;
- Any ongoing employment relationship provided that such employment relationship will be subject to initial review and approval; and
- Any transaction between the Partnership or any of its subsidiaries, on the one hand, and our general partner or any of its affiliates, on the other hand; provided, however, that such transaction is approved consistent with our Partnership Agreement.

Any related person transaction that is identified prior to its consummation will be consummated only if approved by the board of directors of our general partner prior to its consummation. If the related person transaction is identified after it commences, it will be promptly submitted to the board of directors of our general partner or the chairman for ratification, amendment or rescission. If the transaction has been completed, the board of directors of our general partner or the chairman will evaluate the transaction to determine if rescission is appropriate.

In determining whether to approve or ratify a related person transaction, the board of directors of our general partner or the chairman will consider all relevant facts and circumstances, including but not limited to:

- the benefits to the Partnership, including the business justification;
- the impact on a director’s independence in the event the related person is a director or an immediate family member of a director;

- the availability of other sources for comparable products or services;
- the terms of the transaction and the terms available to unrelated third parties or to employees generally; and
- whether the transaction is consistent with our Code of Business Conduct.

The related person transactions policy described above was adopted after the closing of the Initial Offering and, as a result, the transactions and arrangements with MPC described above that were entered into prior to the closing of the Initial Offering were not reviewed under such policy, but were approved by the board of directors of our general partner.

### Director Independence

The information appearing under Item 10. Directors, Executive Officers and Corporate Governance—Director Independence, is incorporated herein by reference.

### Item 14. Principal Accountant Fees and Services

Aggregate fees for professional services rendered for the Partnership by PricewaterhouseCoopers LLP for the years ended December 31, 2017, and December 31, 2016, are presented in the following table:

Fees <sup>(1)</sup> <i>(In thousands)</i>	2017	2016 <sup>(2)</sup>
Audit	\$3,806	\$3,915
Audit-Related	469	—
Tax	1,081	1,329
All Other	2	4
Total	<u>\$5,358</u>	<u>\$5,248</u>

- (1) The Partnership’s Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services Policy is summarized in this Annual Report on Form 10-K. See “Audit Committee Policy for Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services.” In 2017 and 2016, all of these services were pre-approved by the Audit Committee of our general partner in accordance with its pre-approval policy. Our Audit Committee did not utilize the Policy’s de minimis exception in 2017 or 2016.
- (2) These amounts were previously reported in millions as follows: Audit, \$4 million; Audit Related, \$0 million; Tax, \$1 million; and All Other, \$0 million.

The Audit fees for the years ended December 31, 2017, and December 31, 2016, were for professional services rendered for the audit of the financial statements and of internal controls over financial reporting, the performance of regulatory audits, issuance of comfort letters, the provision of consents and the review of documents filed with the SEC.

The Audit-Related fees for the year ended December 31, 2017, were for professional services rendered in relation to updating accounting processes and procedures in order to comply with new accounting pronouncements.

The Tax fees for the years ended December 31, 2017, and December 31, 2016, were for professional services rendered for the preparation of IRS Schedule K-1 tax forms for MPLX LP unitholders and for income tax consultation services.

All Other fees for the years ended December 31, 2017, and December 31, 2016, were for subscriptions to online accounting resources provided by PricewaterhouseCoopers LLP.

The Audit Committee of MPLX GP LLC has considered whether PricewaterhouseCoopers LLP is independent for purposes of providing external audit services to the Partnership and has determined that it is.

### **Audit Committee Policy for Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services**

Among other things, our Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services Policy sets forth the procedure for the Audit Committee to pre-approve all audit, audit-related, tax and permissible non-audit services, other than as provided under a de minimis exception.

Under the policy, the Audit Committee may pre-approve any services to be performed by our independent auditor up to twelve months in advance and may approve in advance services by specific categories pursuant to a forecasted budget. Annually, the executive vice president and chief financial officer of our general partner will present a forecast of audit, audit-related, tax and permissible non-audit services for the ensuing fiscal year to the Audit Committee for approval in advance. The executive vice president and chief financial officer of our general partner, in coordination with the independent auditor, will provide an updated budget to the Audit Committee, as needed, throughout the ensuing fiscal year.

Pursuant to the policy, the Audit Committee has delegated pre-approval authority of up to \$250,000 to the Chair of the Audit Committee for unbudgeted items, and the Chair reports the items pre-approved pursuant to this delegation to the full Audit Committee at the next scheduled meeting.



## **Part IV**

### **Item 15. Exhibits and Financial Statement Schedules**

#### **A. Documents Filed as Part of the Report**

1. Financial Statements (see Part II, Item 8. of this Annual Report on Form 10-K regarding financial statements)
2. Financial Statement Schedules

Financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

Exhibits:

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2.1	Partnership Interests Purchase Agreement dated February 26, 2014, by and between MPLX Operations LLC and MPL Investment LLC	8-K	2.1	3/4/2014	001-35714		
2.2	Partnership Interests Purchase and Contribution Agreement, dated December 1, 2014, by and among MPLX Operations LLC, MPLX Logistics Holdings LLC, MPLX LP and MPL Investment LLC	8-K	2.1	12/2/2014	001-35714		
2.3 †	Agreement and Plan of Merger, dated as of July 11, 2015, by and among MPLX LP, Sapphire Holdco LLC, MPLX GP LLC, MarkWest Energy Partners, L.P. and, for certain limited purposes set forth therein, Marathon Petroleum Corporation	10-Q	2.1	8/3/2015	001-35714		
2.4	Amendment to Agreement and Plan of Merger, dated as of November 10, 2015, by and among MPLX LP, Sapphire Holdco LLC, MPLX GP LLC, MarkWest Energy Partners, L.P. and Marathon Petroleum Corporation	8-K	2.1	11/12/2015	001-35714		
2.5	Amendment Number 2 to Agreement and Plan of Merger, dated as of November 16, 2015, by and among MPLX LP, Sapphire Holdco LLC, MPLX GP LLC, MarkWest Energy Partners, L.P. and Marathon Petroleum Corporation	8-K	2.1	11/17/2015	001-35714		
2.6	Membership Interests Contribution Agreement, dated March 14, 2016, between MPLX LP, MPLX Logistics Holdings LLC, MPLX GP LLC and MPC Investment LLC	8-K	2.1	3/17/2016	001-35714		
2.7	Membership Interests Contributions Agreement, dated March 1, 2017, between MPLX LP, MPLX Logistics Holdings LLC, MPLX Holdings Inc., MPLX GP LLC and MPC Investment LLC	8-K	2.1	3/2/2017	001-35714		
2.8	Membership Interests and Shares Contributions Agreement, dated September 1, 2017, between MPLX LP, MPLX Logistics Holdings LLC, MPLX Holdings Inc., MPLX GP LLC and MPC Investment LLC	8-K	2.1	9/1/2017	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2.9	Membership Interests Contribution Agreement, dated November 13, 2017, between MPLX LP, MPLX Logistics Holdings LLC, MPLX Holdings Inc., MPLX GP LLC and MPC Investment LLC	8-K	2.1	11/13/2017	001-35714		
3.1	Certificate of Limited Partnership of MPLX LP	S-1	3.1	7/2/2012	333-182500		
3.2	Amendment to the Certificate of Limited Partnership of MPLX LP	S-1/A	3.2	10/9/2012	333-182500		
3.3	Fourth Amended and Restated Agreement of Limited Partnership of MPLX LP, dated as of February 1, 2018	8-K	3.1	2/2/2018	001-35714		
4.1	Indenture, dated February 12, 2015, between MPLX LP and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.1	2/12/2015	001-35714		
4.2	First Supplemental Indenture, dated February 12, 2015, between MPLX LP and The Bank of New York Mellon Trust Company, N.A., as Trustee (including Form of Notes)	8-K	4.2	2/12/2015	001-35714		
4.3	Second Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.2	12/22/2015	001-35714		
4.4	Third Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.3	12/22/2015	001-35714		
4.5	Fourth Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.4	12/22/2015	001-35714		
4.6	Fifth Supplemental Indenture, dated as of December 22, 2015, by and between MPLX LP and the Bank of New York Mellon Trust Company, N.A. (including Form of Note)	8-K	4.5	12/22/2015	001-35714		
4.7	Registration Rights Agreement, dated as of May 13, 2016, by and between MPLX LP and the Purchasers party thereto	8-K	4.1	5/16/2016	001-35714		
4.8	Sixth Supplemental Indenture, dated as of February 10, 2017, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.1	2/10/2017	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
4.9	Seventh Supplemental Indenture, dated as of February 10, 2017, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.2	2/10/2017	001-35714		
4.10	Eighth Supplemental Indenture, dated as of February 8, 2018, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.1	2/8/2018	001-35714		
4.11	Ninth Supplemental Indenture, dated as of February 8, 2018, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.2	2/8/2018	001-35714		
4.12	Tenth Supplemental Indenture, dated as of February 8, 2018, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.3	2/8/2018	001-35714		
4.13	Eleventh Supplemental Indenture, dated as of February 8, 2018, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.4	2/8/2018	001-35714		
4.14	Twelfth Supplemental Indenture, dated as of February 8, 2018, between the Issuer and The Bank of New York Mellon Trust Company, N.A., as Trustee	8-K	4.5	2/8/2018	001-35714		
10.1*	MPLX LP 2012 Incentive Compensation Plan	S-1/A	10.3	10/9/2012	333-182500		
10.2	Contribution, Conveyance and Assumption Agreement, dated as of October 31, 2012, among MPLX LP, MPLX GP LLC, MPLX Operations LLC, MPC Investment LLC, MPLX Logistics Holdings LLC, Marathon Pipe Line LLC, MPL Investment LLC, MPLX Pipe Line Holdings LP and Ohio River Pipe Line LLC	8-K	10.1	11/6/2012	001-35714		
10.3	Omnibus Agreement, dated as of October 31, 2012, among Marathon Petroleum Corporation, Marathon Petroleum Company LP, MPL Investment LLC, MPLX Operations LLC, MPLX Terminal and Storage LLC, MPLX Pipe Line Holdings LP, Marathon Pipe Line LLC, Ohio River Pipe Line LLC, MPLX LP and MPLX GP LLC	8-K	10.2	11/6/2012	001-35714		
10.4	Employee Services Agreement, dated effective as of October 1, 2012, by and among Marathon Petroleum Logistics Services LLC, MPLX GP LLC and Marathon Pipe Line LLC	S-1/A	10.6	10/9/2012	333-182500		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.5	Employee Services Agreement, dated effective as of October 1, 2012, by and among Catlettsburg Refining LLC, MPLX GP LLC and MPLX Terminal and Storage LLC	S-1/A	10.7	10/9/2012	333-182500		
10.6	Management Services Agreement, dated effective as of September 1, 2012, by and between Hardin Street Holdings LLC and Marathon Pipe Line LLC	S-1/A	10.8	9/7/2012	333-182500		
10.7	Management Services Agreement, dated effective as of October 10, 2012, by and between MPL Louisiana Holdings LLC and Marathon Pipe Line LLC	S-1/A	10.9	10/18/2012	333-182500		
10.8	Amended and Restated Operating Agreement, dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.3	11/6/2012	001-35714		
10.9	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Patoka tank farm)	S-1/A	10.13	10/9/2012	333-182500		
10.10	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Martinsville tank farm)	S-1/A	10.14	10/9/2012	333-182500		
10.11	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Lebanon tank farm)	S-1/A	10.15	10/9/2012	333-182500		
10.12	Storage Services Agreement, dated effective as of October 1, 2012, by and between Marathon Pipe Line LLC and Marathon Petroleum Company LP (Wood River tank farm)	S-1/A	10.16	10/9/2012	333-182500		
10.13	Storage Services Agreement, dated effective as of October 1, 2012, by and between MPLX Terminal and Storage LLC and Marathon Petroleum Company LP (Neal butane cavern)	S-1/A	10.17	10/9/2012	333-182500		
10.14	Transportation Services Agreement (Patoka to Lima Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.4	11/6/2012	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.15	Transportation Services Agreement (Catlettsburg and Robinson Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.5	11/6/2012	001-35714		
10.16	Transportation Services Agreement (Detroit Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.6	11/6/2012	001-35714		
10.17	Transportation Services Agreement (Wood River to Patoka Crude System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.7	11/6/2012	001-35714		
10.18	Transportation Services Agreement (Garyville Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.8	11/6/2012	001-35714		
10.19	Transportation Services Agreement (Texas City Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.9	11/6/2012	001-35714		
10.20	Transportation Services Agreement (ORPL Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Ohio River Pipe Line LLC	8-K	10.10	11/6/2012	001-35714		
10.21	Transportation Services Agreement (Robinson Products System), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.11	11/6/2012	001-35714		
10.22	Transportation Services Agreement (Wood River Barge Dock), dated as of October 31, 2012, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.12	11/6/2012	001-35714		
10.23*	MPC Non-Employee Director Phantom Unit Award Policy	10-K	10.26	3/25/2013	001-35714		
10.24*	MPLX GP LLC Amended and Restated Non-Management Director Compensation Policy and Equity Award Terms	10-K	10.30	2/24/2017	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.25	First Amendment to Amended and Restated Operating Agreement, dated as of January 1, 2015, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	10-Q	10.2	5/4/2015	001-35714		
10.26	Operating Agreement, dated as of January 1, 2015, between Hardin Street Transportation LLC and Marathon Pipe Line LLC	10-Q	10.3	5/4/2015	001-35714		
10.27	Transportation Services Agreement (Cornerstone Pipeline System and Utica Build-Out Projects), effective as of June 11, 2015, by and between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.1	6/17/2015	001-35714		
10.28	First Amendment to Storage Services Agreement, dated as of September 17, 2015, by and between Marathon Petroleum Company LP and Marathon Pipe Line LLC	8-K	10.1	9/23/2015	001-35714		
10.29	Loan Agreement, by and between MPLX LP and MPC Investment LLC, dated December 4, 2015	8-K	10.1	12/10/2015	001-35714		
10.30*	Letter Agreement, by and between Marathon Petroleum Corporation and Paula L. Rosson, dated October 6, 2015	8-K	10.4	12/10/2015	001-35714		
10.31*	Retention Agreement, by and between Marathon Petroleum Company LP and Greg S. Floerke, dated September 14, 2015	10-K	10.41	2/26/2016	001-35714		
10.32*	Retention Agreement, by and between Marathon Petroleum Company LP and C. Corwin Bromley, dated September 14, 2015	10-K	10.42	2/26/2016	001-35714		
10.33	Employee Services Agreement, dated December 28, 2015, by and between MPLX LP and MW Logistics Services LLC	8-K	10.1	1/4/2016	001-35714		
10.34*	Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple	8-K	10.1	9/11/2007	001-31239		
10.35+	Second Amended and Restated Limited Liability Company Agreement of MarkWest Utica EMG, L.L.C. dated December 4, 2015, between MarkWest Utica Operating Company, L.L.C. and EMG Utica, LLC	10-K	10.48	2/26/2016	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.36	Amended and Restated Transportation Services Agreement, dated January 1, 2015, between Hardin Street Marine LLC and Marathon Petroleum Company LP	8-K	10.1	4/6/2016	001-35714		
10.37	First Amendment to the Amended and Restated Transportation Services Agreement, dated March 31, 2016, between Hardin Street Marine LLC and Marathon Petroleum Company LP	8-K	10.2	4/6/2016	001-35714		
10.38	Amended and Restated Management Services Agreement, dated January 1, 2015, between Hardin Street Marine LLC and Marathon Petroleum Company LP	8-K	10.3	4/6/2016	001-35714		
10.39	Second Amended and Restated Employee Services Agreement, dated January 1, 2015, between Hardin Street Marine LLC and Marathon Petroleum Logistics Services LLC	8-K	10.4	4/6/2016	001-35714		
10.40*	Form of MPLX LP Performance Unit Award Agreement—Marathon Petroleum Corporation Officer	10-Q	10.9	5/1/2017	001-35714		
10.41*	Form of MPLX LP Phantom Unit Award Agreement—Marathon Petroleum Corporation Officer	10-Q	10.7	5/2/2016	001-35714		
10.42*	Form of MPLX LP Performance Unit Award Agreement	10-Q	10.8	5/1/2017	001-35714		
10.43*	Form of MPLX LP Phantom Unit Award Agreement—Officer	10-Q	10.9	5/2/2016	001-35714		
10.44	Series A Preferred Unit Purchase Agreement, dated as of April 27, 2016, by and among MPLX LP and the Purchasers party thereto	8-K	10.1	4/29/2016	001-35714		
10.45	Master Reorganization Agreement, dated September 1, 2016, by and among MPLX Holdings Inc., MarkWest Energy Partners, L.P., MWE GP LLC, MPLX LP, MPLX GP LLC, MPC Investment LLC, MPLX Logistics Holdings LLC and MarkWest Hydrocarbon, L.L.C.	8-K	10.1	9/6/2016	001-35714		
10.46	Second Amendment to Amended and Restated Operating Agreement, dated August 1, 2016, between Marathon Petroleum Company LP and Marathon Pipe Line LLC	10-Q	10.2	10/31/2016	001-35714		



Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.47	First Amendment to Employee Services Agreement, dated May 10, 2016, by and between Marathon Petroleum Logistics Services LLC, MPLX GP LLC and Marathon Pipe Line LLC	10-Q	10.1	8/3/2016	001-35714		
10.48	First Amendment to Amended and Restated Transportation Services Agreement, effective as of April 1, 2016, by and between Marathon Petroleum Company LP and Hardin Street Marine LLC	10-Q	10.2	8/3/2016	001-35714		
10.49	First Amendment to Amended and Restated Management Services Agreement, effective as of November 1, 2016, between Marathon Petroleum Company LP and Hardin Street Marine LLC	10-K	10.62	2/24/2017	001-35714		
10.50	First Amendment to Transportation Services Agreement, dated November 1, 2016, between Marathon Pipeline LLC and Marathon Petroleum Company LP (Texas City Products System)	10-K	10.63	2/24/2017	001-35714		
10.51	Second Amended and Restated Employee Services Agreement, dated March 1, 2017, between Marathon Petroleum Logistics Services LLC, Marathon Pipe Line LLC and MPLX GP LLC	8-K	10.1	3/2/2017	001-35714		
10.52	Transportation Services Agreement, dated January 1, 2015, between Hardin Street Transportation LLC and Marathon Petroleum Company LP	8-K	10.2	3/2/2017	001-35714		
10.53	First Amendment to Transportation Services Agreement, dated December 1, 2016, between Hardin Street Transportation LLC and Marathon Petroleum Company LP	8-K	10.3	3/2/2017	001-35714		
10.54	Second Amendment to Transportation Services Agreement, dated January 1, 2017, between Hardin Street Transportation LLC and Marathon Petroleum Company LP	8-K	10.4	3/2/2017	001-35714		
10.55	Third Amendment to Transportation Services Agreement, dated January 1, 2017, between Hardin Street Transportation LLC and Marathon Petroleum Company LP	8-K	10.5	3/2/2017	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.56	Third Amended and Restated Terminal Services Agreement, dated March 1, 2017, between MPLX Terminals LLC and Marathon Petroleum Company LP	8-K	10.6	3/2/2017	001-35714		
10.57	Third Amended and Restated Employee Services Agreement, effective December 21, 2015, between MPLX Terminals LLC and Marathon Petroleum Logistics Services LLC	8-K	10.7	3/2/2017	001-35714		
10.58*	Form of MPLX LP Phantom Unit Award Agreement—Officer, Cliff Vesting	10-Q	10.1	8/3/2017	001-35714		
10.59	Credit Agreement, dated as of July 21, 2017, among MPLX LP, as borrower, Wells Fargo Bank, National Association, as administrative agent, each of Wells Fargo Securities, LLC, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Mizuho Bank, Ltd., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and RBC Capital Markets, as joint lead arrangers and joint bookrunners, JPMorgan Chase Bank, N.A., as syndication agent, each of Bank of America, N.A., Barclays Bank PLC, Citigroup Global Markets Inc., Mizuho Bank, Ltd., The Bank of Tokyo-Mitsubishi UFJ, Ltd., and Royal Bank of Canada, as documentation agents, and the other lenders and issuing banks that are parties thereto.	8-K	10.1	7/27/2017	001-35714		
10.60*	Amended Restricted Stock Award Agreement	10-Q	10.2	10/30/2017	001-35714		
10.61*	MPLX LP Executive Change in Control Severance Benefits Plan	10-Q	10.3	10/30/2017	001-35714		
10.62	Transportation Services Agreement, dated November 1, 2017, between Marathon Pipe Line LLC and Marathon Petroleum Company LP	8-K	10.1	11/7/2017	001-35714		
10.63	Fourth Amendment to Transportation Services Agreement, dated November 1, 2017, between Hardin Street Transportation LLC and Marathon Petroleum Company LP	8-K	10.2	11/7/2017	001-35714		
10.64	Partnership Interests Restructuring Agreement, dated as of December 15, 2017, among MPLX GP LLC and MPLX LP	8-K	10.1	12/19/2017	001-35714		

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.65	Term Loan Agreement, dated as of January 2, 2018, among MPLX LP, as borrower, Mizuho Bank, Ltd., as administrative agent, each of Mizuho Bank, Ltd., Merrill Lynch, Pierce, Fenner & Smith Incorporated, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Barclays Bank PLC, JPMorgan Chase Bank, N.A., and Wells Fargo Securities, LLC, as joint lead arrangers and joint bookrunners, Bank of America, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Barclays Bank PLC, JPMorgan Chase Bank, N.A., and Wells Fargo Bank, National Association, as syndication agents, and the other lenders and issuing banks that are parties thereto	8-K	10.1	1/4/2018	001-35714		
12.1	Computation of Ratio of Earnings to Fixed Charges					X	
14.1	Code of Ethics for Senior Financial Officers	10-K	14.1	2/24/2017			
21.1	List of Subsidiaries					X	
23.1	Consent of Independent Registered Public Accounting Firm					X	
24.1	Power of Attorney of Directors and Officers of MPLX GP LLC					X	
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350						X
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350						X
101.INS	XBRL Instance Document					X	
101.SCH	XBRL Taxonomy Extension Schema					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase					X	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase					X	

- † The exhibits and schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K and will be provided to the Securities and Exchange Commission upon request.
- \* Indicates management contract or compensatory plan, contract or arrangement in which one or more directors or executive officers of the Registrant may be participants.
- + Application has been made to the Securities and Exchange Commission for confidential treatment of certain provisions of these exhibits. Omitted material for which confidential treatment has been requested and has been filed separately with the Securities and Exchange Commission.

Pursuant to Item 601(b)(4) of Regulation S-K, certain instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10 percent of the total consolidated assets of the Registrant. The Registrant hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request.

**Item 16. Form 10-K Summary**

Not applicable.

## SIGNATURES

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

Date: February 28, 2018

MPLX LP

By: MPLX GP LLC  
Its general partner

By: /s/ C. Kristopher Hagedorn  
C. Kristopher Hagedorn  
Vice President and Controller of MPLX GP LLC  
(the general partner of MPLX LP)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 28, 2018 on behalf of the registrant and in the capacities indicated.

<u>Signature</u>	<u>Title</u>
_____ /s/ Gary R. Heminger Gary R. Heminger	Chairman of the Board of Directors and Chief Executive Officer of MPLX GP LLC (the general partner of MPLX LP) (principal executive officer)
_____ /s/ Pamela K.M. Beall Pamela K.M. Beall	Director, Executive Vice President and Chief Financial Officer of MPLX GP LLC (the general partner of MPLX LP) (principal financial officer)
_____ /s/ C. Kristopher Hagedorn C. Kristopher Hagedorn	Vice President and Controller of MPLX GP LLC (the general partner of MPLX LP) (principal accounting officer)
_____ * Michael J. Hennigan	Director and President of MPLX GP LLC (the general partner of MPLX LP)
_____ * Michael L. Beatty	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * David A. Daberko	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * Timothy T. Griffith	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * Christopher A. Helms	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * Garry L. Peiffer	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * Dan D. Sandman	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * Frank M. Semple	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * John P. Surma	Director of MPLX GP LLC (the general partner of MPLX LP)
_____ * Donald C. Templin	Director of MPLX GP LLC (the general partner of MPLX LP)

\* The undersigned, by signing his name hereto, does sign and execute this report pursuant to the Power of Attorney executed by the above-named directors and officers of the general partner of the registrant, which is being filed herewith on behalf of such directors and officers.

By: /s/ Gary R. Heminger \_\_\_\_\_  
Gary R. Heminger  
Attorney-in-Fact

February 28, 2018

# COMPANY INFORMATION

**Headquarters**  
200 East Hardin St.  
Findlay, OH 45840  
(419) 421-2414

**MPLX LP Website**  
www.MPLX.com

**Investor Relations Office**  
539 South Main St.  
Findlay, OH 45840  
MPLXInvestorRelations@marathonpetroleum.com

Lisa Wilson, Director, Investor Relations  
(419) 421-2071

Doug Wendt, Manager, Investor Relations  
(419) 421-2423

Denice Myers, Manager, Investor Relations  
(419) 421-2965

**Independent Accountants**  
PricewaterhouseCoopers LLP  
406 Washington St., Suite 200  
Toledo, OH 43604

**Stock Exchange Listing**  
New York Stock Exchange

**Common Unit Symbol**  
MPLX

**Principal Unit Transfer Agent**  
Computershare  
Shareholder correspondence should be mailed to:  
P.O. Box 505000  
Louisville, KY 40233-5000

Overnight correspondence should be mailed to:  
462 South 4th Street, Suite 1600  
Louisville, KY 40202  
(877) 373-6374 (toll free – U.S., Canada, Puerto Rico)  
(781) 575-2879 (other non-U.S. jurisdictions)  
web.queries@computershare.com

**Annual Report on Form 10-K**  
Additional copies of the MPLX LP 2017 Annual Report may be obtained by contacting:  
Public Affairs  
539 South Main St.  
Findlay, OH 45840  
(419) 421-3577

**Distributions**  
Distributions on units, as may be declared by the board of directors, are typically paid mid-month in February, May, August and November.

**Tax Reporting**  
MPLX unitholders can access Schedule K-1 tax information by contacting:  
Tax Package Support  
P.O. Box 799060  
Dallas, TX 75379  
(800) 232-0011

**COMPARISON OF CUMULATIVE TOTAL RETURN**  
Among MPLX LP, the S&P 500 Index, the Alerian MLP Index and Peer Group Index



This graph compares the cumulative total return, assuming the reinvestment of distributions, of a \$100 investment in our common units from Dec. 31, 2012, to Dec. 31, 2017, compared to the cumulative total return of an investment in the S&P 500 Index, the Alerian MLP Index and an index of peer companies (selected by us) for the same period. Our peer group consists of the following companies: Andeavor Logistics LP (Tesoro Logistics LP prior to Aug. 1, 2017); Buckeye Partners LP; Enbridge Energy Partners LP; Energy Transfer Partners LP; Enterprise Products Partners LP; Magellan Midstream Partners LP; Phillips 66 Partners LP; Plains All American Pipeline LP; Valero Energy Partners LP; Western Gas Partners LP; and Williams Partners LP.

The performance graph (left) is not "soliciting material" and will not be deemed to be filed with the Securities and Exchange Commission (SEC) or incorporated by reference into any of MPLX's filings with the SEC, except to the extent that we specifically incorporate it by reference into any such filings.





MPLX LP  
200 EAST HARDIN ST.  
FINDLAY, OH 45840

## Non-GAAP Financial Measures

Adjusted earnings before interest, taxes, depreciation and amortization (EBITDA), distributable cash flow (DCF) and distribution coverage ratio are non-GAAP financial measures provided in this annual report. Adjusted EBITDA and DCF reconciliations to the nearest GAAP financial measure are included on Page 9 and in the MPLX Annual Report on Form 10-K for the year ended Dec. 31, 2017, filed with the SEC. Distribution coverage ratio is the ratio of DCF attributable to GP and LP unitholders to total GP and LP distributions declared. Adjusted EBITDA, DCF and distribution coverage ratio are not defined by GAAP and should not be considered in isolation or as an alternative to net income attributable to MPLX, net cash provided by (used in) operating activities or other financial measures prepared in accordance with GAAP. Certain EBITDA forecasts were determined on an EBITDA-only basis. Accordingly, information related to the elements of net income, including tax and interest, are not available and, therefore, reconciliations of these non-GAAP financial measures to the nearest GAAP financial measures have not been provided.

## Disclosures Regarding Forward-Looking Statements

This summary annual report wrap includes forward-looking statements. You can identify our forward-looking statements by words such as "anticipate," "believe," "design," "estimate," "expect," "forecast," "goal," "guidance," "imply," "intend," "objective," "opportunity," "outlook," "plan," "position," "pursue," "prospective," "predict," "project," "potential," "seek," "strategy," "target," "could," "may," "should," "would," "will" or other similar expressions that convey the uncertainty of future events or outcomes. We have based our forward-looking statements on our current expectations, estimates and projections about our industry and our partnership. We caution that these statements are not guarantees of future performance and you should not rely unduly on them, as they involve risks, uncertainties and assumptions that we cannot predict. In addition, we have based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. While our management considers these assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, our actual results may differ materially from the future performance that we have expressed or forecast in our forward-looking statements. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, we have included in our attached Form 10-K for the year ended Dec. 31, 2017, cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

