MPLX LP
Form 10-K
February 26, 2016
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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, 2015
Commission file number 001-35714
MPLX LP
(Exact name of registrant as specified in its charter)

Delaware	27-0005456
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

200 E. Hardin Street, Findlay, Ohio 45840
(Address of principal executive offices)
(419) 672-6500
(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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes x 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 x
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 x 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 x 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. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ¨ No x
The aggregate market value of Common Units held by non-affiliates as of June 30, 2015 was approximately $1.6 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 296,697,253 common units, 7,981,756 Class B units and 6,800,681 general partner units outstanding at February 12, 2016.
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 ter
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, Inc. ("MarkWest Hydrocarbon") and MPLX Pipe Line Holdings LLC ("Pipe Line Holdings"). Pipe Line Holdings owns Marathon Pipe Line LLC ("MPL") and Ohio River Pipe Line LLC ("ORPL"). We have partial ownership interests in a number of joint venture legal entities, including MarkWest Pioneer, L.L.C. ("MarkWest Pioneer"), 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"), Centrahoma Processing LLC ("Centrahoma") and MarkWest EMG Jefferson Dry Gas Gathering Company, L.L.C. ("Jefferson Dry Gas"). References to "MPC" refer collectively to Marathon Petroleum Corporation and its subsidiaries, other than the Partnership.

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Glossary of Terms

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

ARO	Asset retirement obligation
Bbl	Barrels
bcf/d	Billion cubic feet per day
Btu	One British thermal unit, an energy measurement
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
ERCOT	Electric Reliability Council of Texas
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
Initial Offering	Initial public offering on October 12, 2012
LIBOR	London Interbank Offered Rate
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 revenue, less purchased product costs, less any derivative gain (loss)
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
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	Securities and Exchange Commission
SMR	Steam methane reformer, operated by a third party and located at the Javelina gas processing and fractionation complex in Corpus Christi, Texas
VIE	Variable interest entity
WTI	West Texas Intermediate

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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," "estimate," "objective," "expect," "forecast," "goal," "plan," "predict," "project," "potential," "seek," "target," "could," "may," "should," "would," "will" or other similar expressio 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 the MarkWest Merger (as defined below) and other acquisitions 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:

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- changes in general economic, market or business conditions;
- changes in the economic and financial condition of MPLX LP;
- risks and uncertainties associate 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 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;

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- 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, increases in and availability of equity capital, changes in the availability of unsecured credit and changes affecting the credit markets generally; 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.

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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.

At December 31, 2015, our assets included infrastructure to support MPC including approximately 2,900 miles of crude oil and refined product pipelines across nine states. We own a barge dock facility with approximately 78 mbpd of crude oil and product throughput capacity, as well as crude oil and product storage facilities (tank farms) with approximately 4,533 mbbls of available storage capacity. We also own a butane cavern with approximately 1,000 mbbls of available storage capacity. On December 4, 2015, we completed the merger with MarkWest (the “MarkWest Merger”), which is 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. These assets include gathering and processing infrastructure of more than 5,000 miles of gas and NGL pipelines, over 50 gas processing plants, more than 10 NGL fractionation facilities and one condensate stabilization facility.

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. 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, Woodford Shale, Granite Wash formation and the Permian Basin.

As of February 12, 2016, MPC owned our general partner, MPLX GP LLC (“MPLX GP”), and the associated incentive distribution rights, in addition to an approximate 18.2 percent limited partner interest (excluding the Class A units owned by MarkWest Hydrocarbon, a wholly-owned subsidiary of the Partnership, and including the Class B units on an as-converted basis) in us. Given MPC’s significant interest in us, and its stated intent to grow its midstream business, we believe MPC will continue to offer us the opportunity to acquire MLP-qualifying assets from its substantial portfolio of midstream assets. We also have significant organic growth opportunities to expand midstream services throughout major shale plays in the United States. Furthermore, we may pursue third-party midstream acquisitions independently or with MPC to complement our existing geographic footprint or expand our activities into new areas. MPC is under no obligation, however, to offer to sell us additional assets or to pursue acquisitions cooperatively with us, and we are under no obligation to acquire any such additional assets or pursue any such cooperative acquisitions.

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. All of our operations and assets are located in the United States. Maps detailing the individual assets can be found on our website, www.mplx.com. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

RECENT DEVELOPMENTS

On December 4, 2015, we completed the MarkWest Merger. MarkWest is a growth-oriented MLP with leading positions in many natural gas resource plays, including the highly productive Marcellus and Utica shale formations. MarkWest's midstream energy operations include: natural gas gathering, processing and transportation; NGL gathering, transportation, fractionation, storage, and marketing; and crude oil gathering and transportation. MarkWest's assets consist of over 7.0 bcf/d of natural gas processing capacity, over 450 mbpd of NGL fractionation capacity and over 5,000 miles of gas and NGL pipelines. MarkWest's integrated midstream asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States to domestic and international markets. By developing large-scale gathering, processing and fractionation systems in some of the largest supply basins, MarkWest has grown to become one of the largest processors of natural gas and fractionators of NGLs in the United States.

On December 4, 2015, each outstanding common unit of MarkWest was converted into the right to receive (i) 1.09 MPLX LP common units and (ii) $6.20 in cash. Each Class B unit of MarkWest outstanding immediately prior to the merger was 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. On July 1, 2016 and July 1, 2017 (unless earlier converted upon certain fundamental changes regarding MPLX LP), each Class B unit of MPLX LP will automatically convert into 1.09 MPLX LP common units and the right to receive $6.20 in cash. The Class A units of MarkWest outstanding immediately prior to the MarkWest Merger were converted into a specified number of 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 phantom unit representing common units of MarkWest granted under MarkWest's equity plans outstanding immediately prior to the merger fully vested and converted into the right to receive 1.09 MPLX LP common units and $6.20 in cash. The MarkWest Merger resulted in the issuance of 216,350,465 common units and total cash consideration from MPC of approximately $1.3 billion.

In connection with the MarkWest Merger, we assumed an aggregate principal amount of $4.1 billion in senior notes issued by MarkWest and MarkWest Energy Finance Corporation consisting of: $750 million aggregate principal amount of 5.500% senior notes due February 15, 2023; $1.0 billion aggregate principal amount of 4.500% senior notes due July 15, 2023; $1.2 billion aggregate principal amount of 4.875% senior notes due December 1, 2024; and $1.2 billion aggregate principal amount of 4.875% senior notes due June 1, 2025 (collectively, the "MarkWest senior notes"). On December 22, 2015, we completed offers to exchange any and all outstanding MarkWest senior notes for (1) up to $4.1 billion aggregate principal amount of new notes issued by MPLX LP having the same maturity and interest rates as the MarkWest senior notes and (2) cash of $1 for each $1,000 of principal amount exchanged. Approximately 98.4 percent, or $4.0 billion, of MarkWest senior notes were tendered and accepted in the exchange offers.

Effective upon the closing of the MarkWest Merger, our existing credit agreement was amended to, among other things, increase the aggregate amount of revolving credit capacity under the credit agreement by $1.0 billion for total aggregate commitments of $2.0 billion. Also in connection with the MarkWest Merger, MarkWest's bank revolving credit facility was terminated and the approximately $943 million outstanding under that facility was repaid with $850 million of borrowings under MPLX LP's bank revolving credit facility and $93 million of cash.

On December 4, 2015, we 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 us on a revolving basis as requested by us 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, we terminated the previous revolving credit agreement of $50 million with MPC, effective December 31, 2015.

Effective December 4, 2015, we purchased the remaining 0.5 percent interest in Pipe Line Holdings from subsidiaries of MPC for consideration of $12 million. This resulted in Pipe Line Holdings becoming our wholly-owned subsidiary. See Item 8. Financial Statements and Supplementary Data - Note 4 for more information on this transaction.

On January 25, 2016, we announced the board of directors of our general partner had declared a distribution of $0.50 per unit that was paid on February 12, 2016 to unitholders of record on February 4, 2016.

During the third 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, 36,951,515 subordinated units owned by MPC were converted into common units on a one-for-one basis and will prospectively participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of distributions paid by the Partnership or the total units outstanding.

On February 12, 2015, we completed an underwritten public offering of $500 million aggregate principal amount of 4.000% unsecured senior notes due February 15, 2025 (the "Senior Notes"). The Senior Notes were offered at a price to the public of 99.64 percent of par. The net proceeds of this offering were used to repay the amounts outstanding under our bank revolving credit facility, as well as for general partnership purposes.

BUSINESS STRATEGIES

Our primary business objectives are to enhance unitholder returns through the generation of stable cash flows. We intend to accomplish these objectives by executing the following strategies:

Maintain 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 the top-rated midstream service provider since 2006 as determined by an independent research provider.

Increase Operating Cash Flow and Pursue Organic Growth Opportunities. We intend to increase operating cash flow by continuing to grow in our primary areas of operation to meet anticipated demand for additional midstream services. In addition, 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.

Grow through Acquisitions. In addition to the recently completed MarkWest Merger, we plan to continue pursuing acquisitions of complementary assets from MPC as well as third parties. We believe our sponsor will offer us the opportunity to acquire MLP-qualifying assets from its substantial portfolio of midstream assets. We may also pursue third party midstream acquisitions independently or with MPC that complement our existing geographic footprint or expand our activities into new areas.

Focus on Fee-Based Businesses. We are focused on generating stable cash flows by providing fee-based midstream services to our customers. For the full year ended December 31, 2016, we expect fee-based contracts to be approximately 94 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 12 consecutive quarters, which represents a compound annual growth rate of 24 percent over the minimum quarterly distribution. We believe our growth 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:

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

- Our L&S segment's assets are located in regions that collectively comprised approximately 73 percent of total U.S. crude distillation capacity and approximately 53 percent of total U.S. finished products demand for the year ended December 31, 2015, according to the EIA. MPC owns and operates seven refineries in the Midwest and Gulf Coast regions of the United States, which have an aggregate crude oil refining capacity of approximately 1.8 million barrels per calendar day. Our L&S assets are integral to the success of MPC's operations.
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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 February 12, 2016, our assets in the northeastern United States have combined processing capacity of approximately 5.9 bcf/d and combined fractionation capacity of approximately 483 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 and processing of new supplies of natural gas as production in the Northeast continues to increase.

We also have a significant 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

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proximity to other expansion opportunities. We have 1.2 bcf/d of processing capacity in the southwestern portion of the United States.

Leading Midstream Positions Drive Investment Opportunities. Our growth capital plan range for 2016 is $800 million to $1.2 billion. The G&P segment capital plan is primarily for investment in gathering, processing, and fractionation infrastructure in the Marcellus and Utica shale plays, as well as the STACK and SCOOP formations in the Cana-Woodford Shale in Oklahoma and the Permian basin in New Mexico and Texas. The L&S segment capital plan is primarily related to the Cornerstone pipeline project and downstream Utica infrastructure development. The Cornerstone pipeline project is the building block for the other projects that will become a critical solution for the industry to move condensate and natural gas liquids out of the Utica region into refining centers in northwest Ohio and connect the pipelines to Canada. 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 will provide attractive returns and cash flows. We believe MPC will continue to offer us the opportunity to acquire MLP-qualifying assets from its substantial portfolio of midstream assets. 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. We believe MPC to be the largest crude oil refiner in the Midwest and the fourth-largest in the United States based on crude oil refining capacity. MPC is well-capitalized, with investment grade credit ratings, and owns our general partner, an approximate 18.2 percent limited partner interest (excluding the Class A units owned by MarkWest Hydrocarbon, a wholly-owned subsidiary of the Partnership, and including the Class B units on an as-converted basis) in us as of February 12, 2016 and all of our incentive distribution rights. MPC has identified eligible midstream assets and growth projects that are broadly estimated to generate annual EBITDA of $1.6 billion. We believe that our relationship with MPC will provide us with significant growth opportunities, as well as a base of stable cash flows.

High-Quality, Well-Maintained Asset Base. 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, 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 our pipelines.

Stable and Predictable Cash Flows. We generate a substantial majority of our revenue through long-term, fee-based agreements. 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. The table below provides long-term contract details by segment as of December 31, 2015:

	Remaining contract term	% of volumes	
L&S segment	7 years	73	%
G&P segment	4 to 20 years	82	%

Financial Flexibility. As of December 31, 2015, we had $43 million of cash and $1.6 billion available on our revolving credit facilities. We believe that we will have the financial flexibility to execute our growth strategy through our cash reserves, borrowing capacity under our revolving credit facilities and access to the debt and equity capital markets. See Item 8. Financial Statements and Supplementary Data – Note 16 and Note 8 for additional information regarding our recent transactions related to debt and common unit offerings.

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

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ORGANIZATIONAL STRUCTURE

The following diagram depicts our organizational structure and MPC's ownership interests in us as of February 12, 2016.

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We are an MLP with outstanding common units, Class A units and Class B units.

- Our common units are publicly traded on the NYSE under the symbol “MPLX.”
- All of our Class A units are owned by MarkWest Hydrocarbon, which is our wholly-owned subsidiary. The Class A units generally share in our income or losses on a pro rata basis with our common units and our Class B units, however the Class A units do not share in any income or losses that are attributable to our ownership interest (or disposition of such interest) in MarkWest Hydrocarbon. The only impact of the Class A units on our consolidated results of operations and financial position is that MarkWest Hydrocarbon pays income tax on its pro rata share of our income or losses. The Class A units are not treated as outstanding common units in the accompanying Consolidated Balance Sheets as they are all held by our wholly-owned subsidiaries and therefore eliminated in consolidation.
- All of the Class B units were issued to and are held by M&R MWE Liberty LLC and certain of its affiliates (“M&R”), an affiliate of The Energy & Minerals Group (“EMG”). The 8.0 million Class B units will convert into common units at a rate of 1.09 common units per Class B unit and will receive $6.20 in cash per Class B unit, which will be funded by MPC in two equal installments on July 1, 2016 and July 1, 2017. Class B units (i) share in our taxable income and losses, (ii) are not entitled to participate in any distributions of available cash prior to their conversion and (iii) do not have the right to vote on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, unit exchanges and similar statutory authorizations) other than those matters that disproportionately and adversely affect the rights and preferences of the Class B units. Upon conversion of the Class B units, the right of M&R and certain of its affiliates to vote as a common unitholder of the Partnership will be limited to a maximum of five percent of the Partnership’s outstanding common units. Upon the conversion of each tranche of Class B units, M&R will have 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. In addition, M&R may freely transfer such converted units, and M&R will have the right to demand that we conduct up to three underwritten offerings beginning in 2017, but restricted to no more than one offering in any twelve-month period. M&R is not permitted to transfer its Class B units without the prior written consent of our general partner’s board of directors.

INDUSTRY OVERVIEW

We provide services in the midstream sector across the hydrocarbon value chain. Through the execution of the diversified services described below, we create value at various stages. The types of midstream services provided by both our L&S and G&P segments are as follows:

L&S:

MPC owns and operates seven refineries in the Midwest and Gulf Coast regions of the United States, which have an aggregate crude oil refining capacity of approximately 1.8 million barrels per calendar day. Our L&S assets are integral to the success of MPC’s operations.

- Logistics. Crude oil is the basis for many products including plastics and petrochemicals in addition to fuel for trucks and 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 are one of 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, Texas and Canada to numerous refiners. Pipelines are also used to effectively move refined products from refineries to customers and end markets.
- 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 cavern. Storage facilities provide flexibility and logistics optionality, which enhances MPC’s ability to maximize returns for refined products.

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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, and the components of this value chain is 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 typically smaller diameter 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 a central fractionator, multiple products. We operate fractionation facilities at certain processing systems 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.

Historically, the majority of the domestic on-shore natural gas supply has been produced from conventional reservoirs that are characterized by large pockets of natural gas that are accessed using vertical drilling techniques. In the past decade, the supply of natural gas production from the conventional sources has declined as these reservoirs are being depleted. 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

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shift in the source of natural gas production, midstream providers with a significant presence in the shale plays will likely have a competitive advantage.

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. Our assets and operations in each of these segments are described below.

Logistics and Storage

The L&S segment includes transportation and storage of crude oil, refined products and other hydrocarbon-based products. These assets consist of a network of common carrier crude oil and product pipeline systems and associated storage assets in the Midwest and Gulf Coast regions of the United States. We believe our network of petroleum pipelines is one of the largest in the United States, based on total annual volumes delivered. We also own a butane cavern in Neal, West Virginia with approximately 1,000 mbbls of NGLs storage capacity. We are pursuing the Cornerstone pipeline project and downstream Utica infrastructure development, which is the building block for other projects that we expect to become a critical solution for the industry to move condensate and NGLs out of the Utica region into refining centers in northwest Ohio and connect to the pipelines to Canada. We also have planned a butane cavern in Robinson, Illinois, which will be a 1,400-mbbl hard rock mined storage cavern. 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 products at our storage facilities. We are also the operator of additional crude oil and product pipelines owned by MPC and third parties for which we are paid operating fees. 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.

The following is a summary of the significant assets owned by the L&S segment:

Crude Oil Pipeline System Name	Capacity (mbpd)	Associated MPC refineries

Patoka to Lima crude system	249	Detroit, MI; Canton, OH
Catlettsburg and Robinson crude system	495	Robinson, IL; Catlettsburg, KY
Detroit crude system	197	Detroit, MI
Wood River to Patoka crude system	314	All Midwest refineries
Total crude oil pipelines	1,255	

Product Pipeline System Name	Capacity (mbpd)	Associated MPC refineries
Garyville products system	389	Garyville, LA
Texas City products system	215	Texas City, TX; Galveston Bay, TX
ORPL products system	244	Catlettsburg, KY; Canton, OH
Robinson products system	582	Robinson, IL
Louisville airport products system	29	Robinson, IL
Total product pipelines	1,459	

Other L&S Assets	Capacity(1)	Associated MPC refineries
Wood River barge dock	78 mbpd	Garyville, LA
Neal butane cavern	1,000 mbbls	Catlettsburg, KY
Tank farms	4,533 mbbls	Midwest refineries

(1) All capacity shown is for 100 percent of the available storage capacity of our butane cavern and tank farms and 100 percent of the barge dock's average capacity.

Gathering and Processing

Natural Gas Gathering

We operate several natural gas gathering systems that have a combined 5,355 mmcf/d throughput capacity in six 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 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 and C3 fractionation at the Keystone Complex located in Butler County, Pennsylvania (the "Keystone Complex").

MarkWest Utica EMG, our joint venture with an affiliate of EMG, operates two complexes in the Utica Shale, including: gathering, 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"). We also operate a C3+ fractionation complex at the Hopedale Complex located in Harrison County, Ohio (the "Hopedale Complex"). Ohio Condensate, our joint venture with Summit, operates one condensate stabilization facility with 23 mbpd of capacity.

We operate four 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”).

Lastly, we operate three processing 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

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Complex located in Custer and Beckham Counties, Oklahoma (the “Western Oklahoma Complex”); and treating, processing and C2+ fractionation at the Javelina Complex located in Corpus Christi, Texas (the “Javelina Complex”). 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	Key producer customers	Geographic Region
Keystone Complex	410	200	TBD	Rex Energy EdgeMarc Energy[2] PennEnergy[2]	Marcellus Operations
Harmon Creek Complex	—	200	2017	Range Resources	Marcellus Operations
Houston Complex[1]	555	—	N/A	Range Resources	Marcellus Operations
Majorsville Complex[1]	1,070	200	2017	Southwestern Energy[2] CNX[2] Noble[2]	Marcellus Operations
Mobley Complex	720	200	Q1 2016	Range Resources EQT[2] Magnum Hunter[2]	Marcellus Operations
Sherwood Complex	1,200	200	2017	Antero[2]	Marcellus Operations
Cadiz Complex[1]	525	200	2017	Ascent Resources Gulfport	Utica Operations
Seneca Complex[1]	800	—	N/A	Antero[2] Rex Energy	Utica Operations
Kenova Complex	160	—	N/A	Chesapeake[2]	Southern Appalachian Operations
Boldman Complex	70	—	N/A	EQT[2]	Southern Appalachian Operations
Cobb Complex	65	—	N/A	Chesapeake[2]	Southern Appalachian Operations
Langley Complex	325	—	N/A	EQT[2]	Southern Appalachian Operations
Carthage Complex	600	—	N/A	Anadarko Devon Chevron	Southwest Operations
Western Oklahoma Complex	425	—	N/A	Templar EnerVest Newfield Chesapeake	Southwest Operations
West Texas Complex	—	200	Q2 2016	Cimarex[2] Chevron[2]	Southwest Operations
Javelina Complex	142	—	N/A	Valero Flint Hills	Southwest Operations
Total	7,067	1,400			

(1) We have the operational flexibility to process gas for producer customers at either complex.
(2) We do not provide gathering services.

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. We operate several NGL gathering systems for these mixed NGL streams that have a combined 810 mbpd throughput capacity in five states.

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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 Keystone 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
Keystone Complex	47	—	N/A	Railcar and truck loading	Marcellus Operations
Hopedale Complex(1)	120	60	Q2 2017	Key interstate pipeline access Railcar and truck loading	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	262	60			

(1) The Hopedale Complex is jointly owned by MarkWest Liberty Midstream & Resources, L.L.C ("MarkWest Liberty Midstream") and MarkWest Utica EMG, which are entities that operate in the Marcellus and Utica regions, respectively. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data - Note 5.

Ethane Recovery, Transportation and Associated Market Outlets

Due to increased natural gas production from the liquids-rich areas of the Marcellus and Utica Shales, we have begun recovering 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	Ethane expansion capacity	Expected in-service of expansion	Geographic Region

	(mbpd)	under construction (mbpd)	capacity	
Keystone Complex	20	34	Q4 2016	Marcellus Operations
Harmon Creek Complex	—	20	2017	Marcellus Operations
Houston Complex	40	—	N/A	Marcellus Operations
Majorsville Complex	40	—	N/A	Marcellus Operations
Mobley Complex	—	10	Q1 2016	Marcellus Operations
Sherwood Complex	40	—	N/A	Marcellus Operations
Cadiz Complex	40	—	N/A	Utica Operations
Javelina Complex	18	—	N/A	Southwest Operations
Total	198	64		

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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 and the Sherwood Complex to the Houston Complex on a FERC pipeline. Once operational, purity ethane produced at the Mobley Complex will also be transported on this same FERC pipeline to the Houston Complex.
- We deliver purity ethane to Sunoco Logistics Partners L.P.'s ("Sunoco") Mariner West pipeline ("Mariner West") from the Houston Complex and from the Keystone Complex.
- We deliver purity ethane to Enterprise Products Partners L.P.'s Appalachia-to-Texas Express ("ATEX") 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. Beginning 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. By the first quarter of 2016, Mariner East is expected to transport purity ethane in addition to propane to the Marcus Hook Facility.
- Sunoco has 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 the first half of 2017.

For the year ended December 31, 2015, revenues earned from three customers represented 16 percent, 15 percent and 12 percent of G&P segment revenue, respectively. These customers did not account for a significant portion of our consolidated revenue.

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.

Equity Investment in Unconsolidated Affiliates-MarkWest Utica EMG. MarkWest Utica EMG is engaged in providing natural gas gathering, processing, and NGL fractionation, transportation and marketing services in the Utica Shale in eastern Ohio. We own 60 percent of MarkWest Utica EMG.

The financial results for MarkWest Utica EMG and other unconsolidated affiliates are included in Other income in our Consolidated Statements of Income. For a complete discussion of the formation of, and the accounting treatment for, MarkWest Utica EMG and other material unconsolidated affiliates, see Item 8. Financial Statements and Supplementary Data - Note 5.

OUR TRANSPORTATION 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 and storage services agreements with MPC. Under these long-term, fee-based agreements, we provide transportation and storage services to MPC, and MPC has committed to provide us with minimum quarterly throughput volumes on crude oil and products pipelines systems and minimum storage volumes of crude oil, products and butane. All of our transportation services agreements for our crude oil and products pipeline systems (other than our Wood River to Patoka crude system) include a 10-year term and automatically renew for up to two additional five-year terms unless terminated by either party no later than six months prior to the end of the term. The transportation services agreements for our Wood River to Patoka crude system and our Wood River barge dock each include a five-year term and automatically renew for up to four additional two-year terms unless terminated by either party no later than six months prior to the end of the term. Our butane cavern storage services agreement includes a 10-year term but does not automatically renew. 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 no later than six months prior to the end of the term.

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The following table sets forth additional information regarding our transportation and storage services agreements:
Transportation and Storage Services Agreements

Agreement	Initiation Date	Term (years)	MPC minimum commitment[1]
Transportation Services (mbpd)			
Crude systems	October 31, 2012	5-10	745
Product systems	October 31, 2012	10	860
Storage services	October 31, 2012	3-10	5,533

(1) Quarterly commitment for our transportation services agreements in thousands of barrels per day and committed storage capacity for our storage services agreements in thousands of barrels. Volumes shown for crude oil transportation services agreements are adjusted for crude viscosities.

Under our transportation services agreements, 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 our 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 system 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 our Wood River to Patoka crude system and our 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 system, without regard to any minimum volume commitment that may have been in place during the term of the agreement.

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 pipeline systems 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 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 pipeline systems owned by Marathon Petroleum Company LP, a wholly-owned subsidiary of MPC. This fee is currently $14 million and will be adjusted annually for inflation. Marathon Petroleum Company LP has agreed to indemnify MPL against any and all damages arising out of the operation of Marathon Petroleum Company LP's pipeline systems unless such occurrence is due to the gross negligence or willful misconduct of MPL. MPL has agreed to indemnify Marathon Petroleum Company LP against any and all damages arising out of MPL's gross negligence or willful misconduct in the operation of the pipeline systems. The initial term of this agreement was for one year and automatically renews from year-to-year unless terminated by either party at least six months prior to the end of the term.

Our existing operating services agreements include an operating agreement with Red Butte Pipe Line Company, which is owned by a third party. Under this agreement, MPL received $3 million in operating fees for operating certain pipelines in Wyoming and Montana in 2015. The term of this agreement is through December 2018.

Effective February 1, 2013, we entered into an operating agreement with Blanchard Pipe Line Company LLC ("Blanchard Pipe Line"), a wholly-owned subsidiary of MPC, under which we operate various pipeline systems in Texas owned by Blanchard Pipe Line. We received $1 million in fees under this agreement in 2015. This agreement is subject to adjustment for inflation, and in addition, we are reimbursed for specific costs associated with operating the pipeline systems. The initial term of this agreement was for one year and automatically renews year-to-year thereafter unless terminated by either party at least three months prior to the end of the term.

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Effective October 1, 2013, MPL entered into an operating and maintenance agreement with the owners of the Capline pipeline system. The Capline system is a 635 mile, 40-inch crude oil pipeline running from St. James, Louisiana to Patoka, Illinois. MPC owns a 32.6 percent undivided joint interest in the Capline system. We received $4 million in fees under this agreement in 2015. This agreement is subject to adjustment for inflation, and in addition, we are reimbursed for specific costs associated with operating the pipeline system. The initial term of this agreement is until August 31, 2018, and it is automatically extended for successive five year terms thereafter unless terminated by either party at least ten months prior to the end of the term.

Management Services Agreements

Effective September 1, 2012, we entered into a management services agreement with Hardin Street Holdings LLC, a subsidiary of MPC, under which MPL provides certain management services to MPC with respect to certain of MPC's retained assets owned by Hardin Street Holdings LLC. We receive a fixed monthly fee under the agreement for providing the required management services. The fees in 2015 were $1 million. These fees are indexed for inflation and subject to adjustments for changes in the scope of management services provided.

Effective October 10, 2012, we entered into a second management services agreement with MPL Louisiana Holdings LLC, a subsidiary of MPC, under which MPL will continue to provide certain management services to MPC with respect to certain of MPC's retained pipeline assets owned by MPL Louisiana Holdings LLC. We receive a fixed monthly fee under the agreement for providing the required management services. The fees in 2015 were less than $1 million. These fees are indexed for inflation and subject to adjustments for changes in the scope of management services provided.

OTHER AGREEMENTS WITH MPC

We have the following additional agreements with MPC:

- Omnibus Agreement. As of October 31, 2012, we entered into 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 entered into two employee services agreements with MPC, effective October 1, 2012, under which we agreed to reimburse MPC for the provision of certain operational and management services to us in support of our pipelines, barge dock, butane cavern and tank farms. Effective December 28, 2015, we entered into an employee services agreement with MW Logistics Services LLC ("MWLS"), a wholly-owned subsidiary of MPC, under which we agreed to reimburse MWLS for the certain operational and management services to us in support of our G&P segment and certain of our other operations.

OUR RELATIONSHIP WITH MPC

One of our competitive strengths is our relationship with MPC, which we believe to be the largest crude oil refiner in the Midwest and the fourth-largest in the United States based on crude oil refining capacity. MPC owns and operates seven 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 $72 billion in 2015. Marathon Petroleum Corporation's common stock trades on the NYSE under the symbol "MPC."

MPC's operations necessitate large-scale movements of crude oil and feedstocks to and among its refineries, as well as large-scale movements of refined products from its refineries to various markets. To this end, MPC has an extensive portfolio of midstream assets that can potentially be sold and/or contributed to us, providing us with a competitive advantage. As of December 31, 2015, these midstream assets, included:

- approximately 5,400 miles of crude oil and product pipelines that MPC owns, leases or in which it has an ownership interest;
- ownership interest in Southern Access Extension pipeline;
- 19 owned or leased inland towboats and 219 owned or leased inland barges;
- ownership interest in a blue water joint venture with Crowley Maritime Corporation;

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- 61 owned and operated light product terminals with approximately 20 million barrels of storage capacity and 187 loading lanes;
- 18 owned and operated asphalt terminals with approximately 4 million barrels of storage capacity and 68 loading lanes;
- one leased and two non-operated, partially-owned light product terminals;
- 2,210 owned or leased railcars;
- 59 million barrels of tank and cavern storage capacity at its refineries;
- 25 rail and 26 truck loading racks at its refineries;
- seven owned and 11 non-owned docks at its refineries;
- condensate splitters at its Canton, Ohio and Catlettsburg, Kentucky refineries; and
- approximately 20 billion gallons of fuel distribution based on 2015 volumes.

MPC continues to focus resources on growing this portfolio of midstream assets, including investments in the Sandpiper pipeline project, the recently completed Southern Access Extension pipeline and its new marine joint venture, Crowley Ocean Partners.

MPC retains a significant interest in us through its ownership of our general partner, an approximate 18.2 percent limited partner interest (excluding the Class A units owned by MarkWest Hydrocarbon, a wholly-owned subsidiary of the Partnership, and including the Class B units on an as-converted basis) in us and all of our incentive distribution rights. 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 use us to grow its midstream business. As a result, we believe MPC will continue to offer us the opportunity to acquire MLP-qualifying assets from its substantial portfolio of midstream assets. We also may pursue acquisitions cooperatively with MPC which has the balance sheet flexibility and the ability to incubate projects for us to purchase later. However, MPC is under no obligation to offer to sell us additional assets or to pursue acquisitions cooperatively with us, and we are under no obligation to buy any such additional assets or pursue any such cooperative acquisitions.

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: transportation and storage of crude oil; gathering, processing and transmission of natural gas; gathering, transportation, fractionation, exchange and storage of NGLs; and gathering and transportation 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

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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.

- Percent-of-index arrangements - Under percent-of-index arrangements, we purchase natural gas 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 then gather and deliver the natural gas to pipelines where we resell the natural gas at the index price or at a different percentage discount to the index price. Revenue generated from percent-of-index 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. 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.

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.

The following table does not give effect to our active commodity risk management program. For further discussion of how we manage commodity price volatility for the portion of our net operating margin that is not fee-based, see Item 8. Financial Statements and Supplementary Data - Note 15. 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. The calculated percentages for net operating margin for percent-of-proceeds, percent-of-index and keep-whole contracts reflect the partial offset of our natural gas positions. The calculated percentages are less than one percent for percent-of-index due to the offset of our natural gas positions and, therefore, not meaningful to the table below. For the year ended December 31, 2015, we calculated the following approximate percentages of our net operating margin from the following types of contracts:

	Fee-Based		Percent-of-Proceeds[1]		Keep-Whole[2]	
L&S[3]	100	%	—	%	—	%
G&P[3][4]	90	%	8	%	2	%
Total	96	%	3	%	1	%

(1) Includes condensate sales and other types of arrangements tied to NGL prices.
(2) Includes condensate sales and other types of arrangements tied to both NGL and natural gas prices.
(3) Detail on contract types above.
(4) Includes unconsolidated affiliates (See Item 8. Financial Statements and Supplementary Data - Note 5).

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COMPETITION

Within our L&S segment, as a result of our contractual relationship with MPC under our transportation and storage services agreements, and our connections to MPC's refineries, we believe that our crude oil and product pipelines will not face significant competition from other pipelines for MPC's crude oil or products transportation requirements.
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 only ship the minimum volumes through our pipelines (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; and
- major interstate and intrastate pipelines.

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. During the last several years, the number of MLPs and the pace of acquisitions have increased substantially.

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 15 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

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. Historically, the L&S segment has spent approximately two-thirds of both our budgeted maintenance capital expenditures and budgeted pipeline integrity, repair and maintenance expenses during the third and fourth quarter of each calendar year due to our budgeting cycle, operating conditions, weather and safety concerns.

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 pipeline systems 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 "state-of-the-art" real-time transient leak detection system monitors throughput 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 provides for the remote-controlled shutdown of pump stations on the pipeline systems. 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. Certain of our liquids pipeline systems are common carriers subject to regulation by various federal, state and local agencies. FERC regulates interstate transportation on liquids pipeline systems 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 publicly posted on the company's website. Under the ICA, interested persons may challenge new or changed rates or services. 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 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 or on its own motion, existing rates and related rules and may order a pipeline to change them prospectively.

EPAct 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 at the time of the passage of EPAct 1992 for interstate transportation service were deemed just and reasonable and therefore are grandfathered. New rates have since been established after EPAct 1992 for certain pipeline systems, and many of our products rates have subsequently been approved as market-based rates. FERC may change grandfathered rates 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;

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- the complainant was contractually barred from challenging the rate prior to enactment of EPAct 1992 and filed the complaint within 30 days of the expiration of the contractual bar; or
- a provision of the tariff is unduly discriminatory or preferential.

EPAct 1992 required FERC to establish a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows petroleum pipelines to change their rates within prescribed ceiling levels that are tied to changes in the PPI. FERC’s indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2011 and ending June 30, 2016, petroleum pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 2.65 percent. During the five-year period commencing July 1, 2016, petroleum pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23 percent. 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 increase in costs. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling, unless the pipelines request and receive a waiver from FERC permitting them not to apply the negative index adjustment.

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 non-affiliated shippers. We have used index rates, settlement rates and market-based rates to change the rates for our different FERC regulated petroleum pipeline systems.

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. Finally, FERC’s income tax policy continues to be the subject of various appeals by shippers, before FERC and the courts. To this point, FERC and the courts have upheld the policy, but we cannot guarantee either of them will not make changes to the policy in the future.

Intrastate services provided by certain of our liquids pipeline systems are subject to regulation by state regulatory authorities, such as the Illinois Commerce Commission and the Michigan Public Service Commission. This state regulation uses a complaint-based system, both as to rates and priority of access. The Illinois Commerce Commission and the Michigan Public Service Commission 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, like ours, have not been 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. However, 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:

- 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;

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- 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.

Because some of our pipelines are common carrier pipelines, we may be required to accept new shippers who wish to transport on our pipelines. It is possible that new shippers, current shippers or other interested parties may decide to challenge our tariff rates and/or the terms of service for our pipelines, including proration rules.

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

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 (“2005 EPAct”). Under the 2005 EPAct, FERC may impose civil penalties of up to $1,000,000 per day for each current violation of the NGA. The 2005 EPAct 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 EPAct. 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. In 2008, FERC issued revised standards of conduct for transmission providers in Order 717, as amended and clarified in subsequent orders on rehearing, to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. A "Transmission Provider" includes an interstate natural gas pipeline that provides open access transportation pursuant to FERC's regulations. 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

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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. The Partnership typically files the report required by Order 704 on behalf of its subsidiaries that engage in reportable transactions.

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 are required to implement the new standards in 2016.
On November 15, 2012, FERC issued a Notice of Inquiry in Docket No. RM 13-1-000 requesting comments on whether it should propose to require the quarterly reporting of certain data relating to next-day and next-month transactions. FERC issued data requests to certain natural gas marketers in July 2013 and FERC has not proceeded with any further action in the docket since that time.

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 are pending 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 FERC 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 meet the traditional tests FERC uses to establish a 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

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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 proposing possible changes to the scope and applicability of 49 C.F.R. Part 192, which governs construction standards and operation of natural gas gathering pipelines. Depending upon the nature of the final rule-making, those could have an impact upon MPLX operations.

Natural Gas Processing. Our natural gas processing operations are not presently subject to FERC or state 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 allowables 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 subject to safety regulation by the DOT under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines. Currently, PHMSA is proposing 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 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.

Pipeline Interconnections. One or more of our plants include pipeline interconnections 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, including the obligation to file a FERC tariff. 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. Three of our facilities have been preliminarily classified as subject to the Department of Homeland Security Chemical Facility Anti-Terrorism Standards. In addition, we have two 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 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. For instance, the EPA is currently taking a closer look at pipeline maintenance operations, and the result of this closer review may yield modified emission calculations and/or regulations relating to such activities. 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 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 related to our assets 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

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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 liabilities for the costs of removing or remediating hazardous substances that have been released into the environment, for restoration costs and damages to natural resources and for the costs of certain health studies. 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. While we are required to comply with RCRA requirements relating to hazardous wastes, currently our operations generate minimal quantities of such hazardous wastes. However, 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. We do not believe that there presently exists significant surface and subsurface contamination of our properties by petroleum hydrocarbons or other wastes for which we are currently responsible.

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, investigatory or remedial activities with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of a September 1994 "Administrative Order by Consent for Removal Actions" with EPA Regions II, III, IV and V; and with respect to the Boldman Complex, an "Agreed Order" entered into by the third-party owner/operator with the Kentucky Natural Resources and Environmental

Protection Cabinet in October 1994. 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, any environmental liabilities associated with the EPA Administrative Order, the Kentucky Agreed Order 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 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.

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,

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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 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 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 June 2015, the EPA and the United States Army Corps of Engineers finalized significant changes to the definition of the term “waters of the United States” (“WOTUS”) used in numerous programs under the Clean Water Act. This final rulemaking is referred to as the “Clean Water Rule.” The Clean Water Rule has been challenged in multiple federal courts by many states, trade groups, and other interested parties, and in October 2015, a United States Court of Appeals issued a nationwide stay of the Clean Water Rule. The Clean Water Rule, as written, expands permitting, planning and reporting obligations and may extend the timing to secure permits for pipeline and fixed asset construction and maintenance activities. The Clean Water Rule does contain new language intended to address concerns that the proposed rule included storm water conveyances and storage structures as WOTUS, and we continue to review how that new language will apply under specific circumstances. Court challenges of the Clean Water Rule will continue through 2016.

In addition, the transportation and storage of crude oil and 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 cause.

Hydraulic Fracturing

We do not conduct hydraulic fracturing operations, but we do provide gathering, processing and fractionation services with respect to natural gas 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 BLM published its final rule setting new standards for hydraulic fracturing on onshore federal and Indian lands. The final rules have been challenged. 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 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. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Most notably, in June 2015, the EPA released its draft assessment of the impacts of hydraulic fracturing on drinking water. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, 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 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 8-hour primary and secondary standards protective of public health and public welfare. In light of the revised ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations and those of our producer customers. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. Federal and state regulators and agencies are also currently taking a closer look at pipeline maintenance operations and any emissions and permits that may be related to such activities. The result of this closer review may yield modified emission calculations and/or regulations relating to such activities or potentially enforcement actions by the agencies for unaccounted for or unpermitted emissions. State and federal agencies have also proposed revisions to regulations or interpretations of regulations regarding aggregation of facilities for permitting purposes and performance standards for methane emissions from new and modified oil and gas production and natural gas processing and transmission facilities, any of which

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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 MPC's refineries from which we receive significant revenues. MPC has been required in the past, and will be required in the future, to incur significant capital expenditures to comply with new legislative and regulatory requirements relating to its operations. To the extent these capital expenditures have a material effect on MPC, they could have a material effect on our business and results of operations. We have been in discussions with various state agencies in the areas in which we operate with respect to their guidance, policies, rules and regulations regarding the permitting process, source determination, categories of applicable permits and control technology that may be required for the construction or operation of certain of our facilities. We believe that our operations are in substantial compliance with applicable air permitting and control technology requirements.

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. In addition, the EPA is gathering information regarding existing facilities in various industries which may be used to support potential future regulation of GHGs. 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 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 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. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas sources in the United States, including, among others, certain onshore and offshore oil and natural gas production and onshore oil and natural gas processing, fractionation, transmission, storage and distribution facilities, which includes certain of our operations. In addition, in 2015, the EPA issued rules expanding the petroleum and natural gas system sources for which annual GHG emissions reporting is required to include GHG emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. 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. Additionally, in 2015 the EPA finalized rules to limit GHG emissions from new and existing power plants. The requirements could increase the cost of electricity and natural gas for our operations and ultimately states could impose additional GHG emission reduction requirements. In sum, requiring reductions in GHG emissions at our facilities could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities and (iii) administer and manage any GHG emissions programs, including acquiring emission credits or allotments. These requirements may also significantly affect MPC's refinery operations and may have an indirect effect on our business, financial condition and results of operations.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and while there has not been federal climate legislation adopted in the United States in recent years, 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. If Congress were to undertake comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for oil, natural gas, NGLs and products derived therefrom. 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 also proposed a rule in the Federal Register on September 18, 2015 that will set 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. 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

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available for distribution to our unitholders.

Endangered Species Act and Migratory Bird Treaty Act Considerations

The federal Endangered Species Act ("ESA") and analogous laws regulate activities that may affect endangered or threatened species, including their habitats. If endangered species are located in areas where we propose to construct new gathering or transportation pipelines or processing or fractionation facilities, 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. We also may be obligated to develop plans to avoid potential takings of protected species, 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 increase 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 March 2014, the FWS announced the listing of the lesser prairie chicken as a threatened species under the ESA. Both 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 the construction of our facilities or limitations on 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 a permit. If there is the potential to adversely affect migratory birds as a result of our operations or construction activities, we may be required to obtain necessary permits 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 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 HLPSA. The HLPSA 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

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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 pipeline systems 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 pipeline systems, including inspecting and reburying 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). In addition, on October 18, 2010, PHMSA issued an advance notice of proposed rulemaking on a range of topics relating to the safety of natural gas, crude oil and other hazardous liquids pipelines. On October 13, 2015, PHMSA issued a notice of proposed rulemaking which purposes changes to 49 CFR Part 195. 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 conforms 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 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. 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. 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 pipeline systems 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. Neither we nor our subsidiaries have any employees as of January 1, 2016. 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 2,200 full-time employees that provide services to us under our employee services agreements, of which 1,440 are from the MarkWest Merger. 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, 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 $5.3 billion as of December 31, 2015, and we may incur significant additional debt obligations in the future. 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:

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- 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 sequestration, 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

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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 fluctuation and decline in natural gas, NGL and oil prices currently occurring has adversely impacted 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 lower unit price could also trigger an impairment analysis of our goodwill and intangible assets. The significant decline in oil prices that occurred in 2015 and is continuing into 2016 has impacted our common unit price. The high and the low market price of our common units in 2015 ranged from a high of $85.57 to a low of $26.38. Subsequent to December 31, 2015, our common units have been as low as $16.53. Given the significant change in MLP valuations and the resultant higher distribution yield environment the sector experienced in 2015, our cost of capital has increased, which could impair our ability to grow our business and make distributions to unitholders at intended levels. The severe decline in oil prices that occurred late in 2014, which has continued through 2015 and into 2016, has increased the volatility and amplitude of the other risks as described in this report and has impacted our unit price. If this continues, this may have an impact on our business and financial condition. A continued decline in our unit price may adversely affect our ability to access the capital markets on acceptable terms.
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 distributions 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.

Our inability, or limited ability, to control certain aspects of management of joint venture legal entities that we have a partial ownership interest in 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 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

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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.

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, pipeline 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.

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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 15. Derivative Financial Instruments.

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 creditworthy 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. 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 many cases, we market NGLs on behalf of our producer customers, and as a result, we may make such commitments on behalf of our 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. 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, particularly to the extent sales are denominated in foreign currencies as we do not currently hedge against 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, 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 those joint venture partners who exercise this right may have a competitive advantage due to their familiarity with our business arising from our joint venture arrangements, or 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.

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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. 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 due to the sustained decline of natural gas, NGL and oil prices that has occurred. 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.

If we are unable to make strategic acquisitions on economically acceptable terms from MPC or third parties, our ability to implement our business strategy may be impaired.

In addition to organic growth, a component of our business strategy can include the expansion of our operations through strategic acquisitions, including acquisitions from MPC. 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 the MarkWest Merger or our future acquisitions, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transaction.

Our future growth may depend in part on our ability to integrate our future acquisitions. We cannot guarantee that we will successfully integrate the MarkWest Merger 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, including the MarkWest Merger, 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.

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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. 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 matters, 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.

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 and NGL pipelines, and various of our crude oil 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 NGL product pipelines and for the crude oil and refined product common carrier pipelines, we have a FERC tariff on file and we may have additional common carrier pipelines in the future that may be subject to these requirements. We also own and are constructing pipelines that are carrying or are expected to carry NGLs owned by us across state lines between our processing and fractionation facilities that we believe are either not subject to FERC’s requirements for common carrier NGL pipelines or would otherwise meet the qualifications for a waiver from many of FERC’s reporting and filing 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 for common carrier pipelines and/or are otherwise not exempt from its reporting and filing 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 -Rate and Other Regulation as set forth in this Annual Report on Form 10-K.

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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 the FERC. The FERC prescribes rate methodologies for developing regulated tariff rates for these natural gas, interstate oil and products pipelines. The FERC's regulated tariff may not allow us to recover all of our costs of providing services. Changes in the 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 the FERC may investigate) the lawfulness of tariff rates. The 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 rights-of-way or other property rights or to renew existing rights-of-way or 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 for land on which any of our processing 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 December 2015, and interest rates may continue to increase in the future. 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 will 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.

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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 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 pipeline systems 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, 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. For example, it is possible that future amendment or re-interpretation of existing air emission laws could impose more stringent permitting or pollution control equipment requirements on us if two or more of our facilities are aggregated into one air emissions permit or permit application, which could increase our costs. 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 - Rate and Other Regulation, Item 1. Business - Environmental Regulation, and Item 1. Business - Pipeline Safety, 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 adopted regulations establishing PSD construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that are potential major sources of certain principal, or criteria, pollutant emissions. In addition, the EPA and states are gathering information on existing facilities in various industries, which may be used to support potential future regulation of carbon emissions, and 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 EPA or states implemented more stringent permitting requirements relating to GHG emissions without regard to non-GHG criteria pollutants, we may be required to install “best available control technology” 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 our construction and operating costs may materially increase.

Congress has from time to time considered legislation to reduce emissions of GHGs, but, in the absence of federal climate legislation in the United States in recent years, 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 to acquire and surrender emission allowances in return for emitting those GHGs. If Congress were to undertake comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for oil, natural gas, NGLs and products derived therefrom.

These requirements or enforcement thereof, or the adoption of any new legislation or regulations that requires additional reporting, monitoring or recordkeeping of GHGs, limits emissions of GHGs from our equipment and operations, or imposes a carbon tax, could adversely affect our operations and materially restrict or delay our ability to obtain air permits for new or modified facilities, could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we process or fractionate. EPA and some states have also proposed new regulations that will set 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, and the Commonwealth of Pennsylvania has also proposed similar regulations. 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. 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 Matters-Climate Change.

Finally, for a variety of reasons, natural and/or anthropogenic, some members of the scientific community believe that climate changes could occur which could have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations, which in turn could adversely affect our cash available for distribution to our unitholders.

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. At the state level, 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, 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
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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.

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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.

In addition, the maximum civil penalty for federal pipeline safety violations has increased from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. 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 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 its 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.
Interruptions in operations at any of our facilities or 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, 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 facilities MPC’s refining operations 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, processing and fractionation plants and associated facilities;

- disruption in our supply of power, water and other resources necessary to operate our facilities;
- damage to our facilities resulting from gas, crude oil, NGLs or refined products that do not comply with applicable specifications; and

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- inadequate fractionation, transportation or storage capacity or market access to support production volumes, including lack of availability of rail cars, 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.
In addition, 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.
Our operations depend on the use of information technology ("IT") systems that could be the target of industrial espionage or cyber-attack.

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. 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 or damage our facilities or those of third parties, which could have a material adverse effect on our revenues and increase our operating and capital costs, which could 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. To protect against such attempts of unauthorized access or attack, we have implemented infrastructure protection technologies and disaster recovery plans. There can be no guarantee such plans, to extent they are in place, will be effective.
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 the substantial majority of our revenues in 2015 and will account for a large portion 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 pipelines 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, 2015, 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 72 percent of our revenues and other income. While we believe MPC will continue to account for a large portion of our revenues on a go forward basis, due to the MarkWest Merger, in 2016, we expect for MPC to account for significantly less of our revenues and other income. 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 pipeline systems or the ability of MPC to utilize third-party pipeline connections to access our pipeline systems;
- 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.

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 system 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 system 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 system until any such remaining credits were fully used or until the expiration

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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, 2015, MPC had long-term indebtedness of approximately $12 billion. 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.

The recent lifting of the U.S. crude oil export ban could adversely affect crack spreads or crude oil price differentials and have a material adverse effect on our business, financial condition, results of operations and cash flows.

Since the 1970s, the U.S. has restricted the ability of producers to export domestic crude oil. In December 2015, U.S. lawmakers passed legislation to lift the crude oil export ban. The lifting of the crude oil export ban may cause the price of domestic crude oil to rise, potentially impacting crack spreads and price differentials between domestic and foreign crude oils. A deterioration of crack spreads or price differentials between domestic and foreign crude oils could reduce the volumes of crude oil and refined products that MPC delivers to us, which in turn could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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 Internal Revenue Service ("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 35 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.

The sale or exchange of 50 percent or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50 percent threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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 fifteen (15) 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, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and 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. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded limited partnerships. For example, on May 6, 2015, the IRS and the U.S. Department of Treasury published proposed regulations that provide industry-specific guidance regarding whether income earned from certain activities will constitute qualifying income. Although these proposed regulations do not appear as if they would affect our treatment as a partnership, we are unable to predict whether the final version of such regulations will have any such effect. In addition, in connection with the proposed budget for the 2017 fiscal year, President Obama has proposed, among other things, to remove the exception for fossil fuel publicly traded partnerships, to impose a $10.25 per barrel equivalent tax on petroleum products, and certain other changes that may increase the amount of taxes paid by unitholders in publicly traded partnerships. 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. In addition, as to possible additional legislation, we cannot predict whether any proposals will be introduced, reintroduced or ultimately enacted. Any such changes could affect us and negatively impact the value of an investment in our units.

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 an approximate 18.2 limited partner interest (excluding the Class A units owned by MarkWest Hydrocarbon, a wholly-owned subsidiary of the Partnership, and including the Class B units on an as-converted basis) in us as of February 12, 2016. 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. 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, even if the borrowing is to allow us to pay the general partner's incentive distribution rights;
- our partnership agreement permits us to classify up to $60.0 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 in respect of the general partner interest or the incentive distribution rights;
- 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;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner, which we refer to as our conflicts committee, or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

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

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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 general partner has certain incentive distribution rights that may reduce the amount of our cash available for distribution to our common unitholders.

Our general partner currently holds a general partner interest in us that entitles it to receive two percent of all distributions paid to our common, and potentially our Class A, unitholders and incentive distribution rights that entitle it to receive an increasing percentage (13 percent, 23 percent and 48 percent) of the cash that we distribute to our common, and potentially our Class A, unitholders from available cash after the minimum quarterly distribution and certain target distribution levels have been achieved. The maximum distribution right for our general partner to receive 48 percent of any distributions paid to our common, and potentially our Class A, unitholders does not include any distributions that our general partner or its affiliates may receive on common or general partner units that they own. As of December 31, 2015, our general partner was at the top tier of the incentive distribution rights scale. While MarkWest Hydrocarbon is a subsidiary of MPLX, the amounts payable to our general partner will be based on the distributions paid to our common unitholders. If at some point MarkWest Hydrocarbon is not a subsidiary of MPLX then the amounts payable to our general partner will be based on the distributions paid to both our common and Class A unitholders, which would increase the amount payable to our general partner. Because a higher percentage of our cash may be allocated to our general partner due to these incentive distribution rights, our cost of capital may increase over time, making investments, capital expenditures and acquisitions, and therefore, future growth, by us more costly.

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 cannot 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 12, 2016, our general partner and its affiliates owned approximately 19.2 percent of the 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.

Our general partner interest, the control of our general partner and the incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, 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.

Additionally, our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of MPC selling or contributing additional midstream assets to us, as MPC would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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 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 equity securities that may effectively rank senior to our common units as to distributions or liquidations. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- 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 December 31, 2015, MPC held 56,932,134 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

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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.

Our general partner, or any transferee holding incentive distribution rights, may elect to cause us to issue common units and general partner units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of our conflicts committee or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received distributions on its incentive distribution rights at the highest level to which it is entitled (48 percent, in addition to distributions paid on its two percent general partner interest, each as of December 31, 2015) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and general partner units. The number of common units to be issued to our general partner will be equal to that number of common units that would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Our general partner will also be issued the number of general partner units necessary to maintain our general partner's interest in us at the level that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive distributions based on the initial target distribution levels. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of distributions that they would have otherwise received had we not issued new common units and general partner units in connection with resetting the target distribution levels. Additionally, our general partner has the right to transfer all or any portion of our incentive distribution rights at any time, and such transferee shall have the same rights as the general partner relative to resetting target distributions if our general partner concurs that the tests for resetting target distributions have been fulfilled.

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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 Pipeline Systems

The following table sets forth certain information regarding our crude oil pipeline systems as of December 31, 2015, each of which has an associated transportation services agreement with MPC (other than the inactive pipelines):

System name	Diameter (inches)	Length (miles)	Capacity (mbpd)[1]	Associated MPC refineries
Patoka to Lima crude system				
Patoka, IL to Lima, OH	20"/22"	304	249	Detroit, MI; Canton, OH
Catlettsburg and Robinson crude system				
Patoka, IL to Robinson, IL	20"	78	225	Robinson, IL
Patoka, IL to Catlettsburg, KY	24"/20"	406	270	Catlettsburg, KY
Subtotal		484	495	
Detroit crude system				
Samaria, MI to Detroit, MI	16"	44	117	Detroit, MI
Romulus, MI to Detroit, MI[2]	16"	17	80	Detroit, MI
Subtotal		61	197	
Wood River to Patoka crude system				
Wood River, IL to Patoka, IL	22"	57	215	All Midwest refineries
Roxanna, IL to Patoka, IL[3]	12"	58	99	All Midwest refineries
Subtotal		115	314	
Inactive pipelines		44	N/A	
Total crude oil pipelines		1,008	1,255	

(1) Capacity shown is 100 percent of the capacity of these pipeline systems 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.

Our crude oil pipeline systems 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 system; Western Canada, Wyoming and North Dakota on the Keystone, Platte, Mustang and Enbridge pipeline systems; and the Gulf Coast on the Capline crude oil pipeline system. Our major crude oil pipeline systems are connected to these supply hubs and transport crude oil to refineries owned by MPC and third parties.

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Product Pipeline Systems

The following table sets forth certain information regarding our product pipeline systems as of December 31, 2015, each of which has an associated transportation services agreement with MPC (other than our Louisville airport products system, which currently transports only third-party volumes, and the inactive pipelines):

System name	Diameter (inches)	Length (miles)	Capacity (mbpd)[1]	Associated MPC refineries
Garyville products system				
Garyville, LA to Zachary, LA	20”	70	389	Garyville, LA
Zachary, LA to connecting pipelines[2]	36”	2	—	Garyville, LA
Subtotal		72	389	
Texas City products system				
Texas City, TX to Pasadena, TX	16”	39	215	Texas City, TX; Galveston Bay, TX
Pasadena, TX to connecting pipelines[2]	36”/30”	3	—	Texas City, TX; Galveston Bay, TX
Subtotal		42	215	
ORPL products system				
Kenova, WV to Columbus, OH	14”	150	68	Catlettsburg, KY
Canton, OH to East Sparta, OH[3,4]	6”	17	73	Canton, OH
East Sparta, OH to Heath, OH[4]	8”	81	29	Canton, OH
East Sparta, OH to Midland, PA[4]	8”	62	32	Canton, OH
Heath, OH to Dayton, OH	6”	108	24	Catlettsburg, KY; Canton, OH
Heath, OH to Findlay, OH	10”/8”	100	18	Catlettsburg, KY; Canton, OH
Subtotal		518	244	
Robinson products system				
Robinson, IL to Lima, OH	10”	250	51	Robinson, IL
Robinson, IL to Louisville, KY	16”	129	92	Robinson, IL
Robinson, IL to Mt. Vernon, IN[5]	10”	79	77	Robinson, IL
Wood River, IL to Clermont, IN	10”	317	48	Robinson, IL
Dieterich, IL to Martinsville, IL	10”	40	59	Robinson, IL
Wabash Pipeline System:				
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[6]	16”/12”	140	85	Robinson, IL
Subtotal		1,171	582	
Louisville airport products system				
Louisville, KY to Louisville International Airport	8”/6”	14	29	Robinson, IL
Inactive pipelines[7]		83	n/a	
Total product pipelines		1,900	1,459	

(1) Capacity shown is 100 percent of the capacity of these pipeline systems.
(2) Capacity not shown, as the pipeline is designed to meet outgoing capacity for connecting third-party pipelines.
(3) Consists of two separate approximately 8.5-mile pipelines.
(4) This pipeline is bi-directional.
(5) This pipeline is leased from a third party.

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(6) Capacity not shown for 16 miles on this system due to complexities associated with bi-directional capability.
(7) Includes 77 miles of pipeline leased from a third party.

Our product pipeline systems 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 pipeline systems also supply feedstocks to MPC's Midwest refineries. These product pipeline systems are integrated with MPC's expansive network of refined product marketing terminals, which support MPC's integrated midstream business.

Other L&S Assets

The following table sets forth certain information regarding our other midstream assets as of December 31, 2015, each of which currently has an associated transportation services agreement or storage services agreement with MPC:

Asset name	Capacity[1]	Associated MPC refineries
Wood River Barge Dock	78 mbpd	Garyville, LA
Neal Butane Cavern	1,000 mbbls	Catlettsburg, KY
Patoka Tank Farm	2,626 mbbls	All Midwest refineries
Wood River Tank Farm	419 mbbls	All Midwest refineries
Martinsville Tank Farm	738 mbbls	Detroit, MI; Canton, OH
Lebanon Tank Farm	750 mbbls	Detroit, MI; Canton, OH

(1) All capacity shown is for 100 percent of the available storage capacity of our butane cavern and tank farms and 100 percent of the barge dock's average capacity.

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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, 2015. 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[(1)(2)] (mmcf/d)	Utilization of Design Capacity[(1)]	
Marcellus Shale:					
Keystone Complex	Butler County, PA	410	275	67	%
Houston Complex	Washington County, PA	555	320	58	%
Majorsville Complex	Marshall County, WV	1,070	938	88	%
Mobley Complex	Wetzel County, WV	720	616	86	%
Sherwood Complex	Doddridge County, WV	1,200	815	68	%
Total Marcellus Shale		3,955	2,964	75	%
Utica Shale:					
Cadiz Complex	Harrison County, OH	525	475	90	%
Seneca Complex	Noble County, OH	800	661	83	%
Total Utica Shale		1,325	1,136	86	%
Southern Appalachia:					
Kenova Complex[(3)]	Wayne County, WV	160	111	69	%
Boldman Complex[(3)]	Pike County, KY	70	40	57	%
Cobb Complex	Kanawha County, WV	65	26	40	%
Kermit Complex[(3)(4)]	Mingo County, WV	32	N/A	N/A	
Langley Complex	Langley, KY	325	66	20	%
Total Southern Appalachia[(3)]		620	243	39	%
Southwest:					
Carthage Complex	Panola County, TX	600	516	86	%
Western Oklahoma Complex	Custer and Beckham Counties, OK	425	300	71	%
Javelina Complex	Corpus Christi, TX	142	114	80	%
Total Southwest[(5)]		1,167	930	80	%
Total Gas Processing		7,067	5,273	75	%

(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) Natural gas throughput includes volumes from December 4, 2015 to December 31, 2015.

(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 capacity has been excluded from the subtotal.

(5) Centrahoma processing capacity of 300,000 mmcf/d is not included in this table as we own a non-operating interest.

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Fractionation Facilities

Facility	Location	Design Throughput Capacity (mbpd)	NGL Throughput[(1)(2)] (mbpd)	Utilization of Design Capacity[(1)]	
Marcellus Shale:					
Keystone Complex[(3)(4)]	Butler County, PA	47	10	21	%
Houston Complex[(3)]	Washington County, PA	60	62	103	%
Total Marcellus Shale		107	72	67	%
Hopedale Complex[(3)(5)]	Harrison County, OH	120	109	91	%
Utica Shale:					
Ohio Condensate Complex[(6)]	Harrison County, OH	23	17	74	%
Total Utica Shale		23	17	74	%
Southern Appalachia:					
Siloam Complex[(7)]	South Shore, KY	24	12	50	%
Total Southern Appalachia		24	12	50	%
Southwest:					
Javelina Complex	Corpus Christi, TX	11	9	82	%
Total Southwest		11	9	82	%
Total C3+ Fractionation and Condensate Stabilization		285	219	77	%

(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) NGL throughput includes volumes from December 4, 2015 to December 31, 2015.

(3) Our Houston, Hopedale and Keystone Complexes have above ground NGL storage with a usable capacity of 26 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 nine million gallons of butane storage and 11 million gallons of propane storage with third parties that can be utilized by our assets in the Marcellus Shale and Utica Shale.

(4) Includes 33 mbpd of de-propanization only capacity.

(5) Our Hopedale System is jointly owned by MarkWest Liberty Midstream and MarkWest Utica EMG, respectively. We account for MarkWest Utica EMG as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data - Note 5.

(6) The Ohio Condensate Complex has up to seven million gallons of condensate storage. The Ohio Condensate Complex is partially owned by MarkWest Utica EMG Condensate. We account for Ohio Condensate as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data - Note 5.

(7) 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 barges up to 840,000 gallons.

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De-ethanization Facilities

Facility	Location	Design Throughput Capacity (mbpd)	NGL Throughput[(1)(2)] (mbpd)	Utilization of Design Capacity[(1)]	
Marcellus Shale:					
Keystone Complex	Butler County, PA	20	10	50	%
Houston Complex	Washington County, PA	40	21	53	%
Majorsville Complex	Marshall County, WV	40	42	105	%
Sherwood Complex	Doddridge County, WV	40	10	32	%
Total Marcellus Shale		140	83	65	%
Utica Shale:					
Cadiz Complex	Harrison County, OH	40	6	15	%
Total Utica Shale		40	6	15	%
Southwest:					
Javelina Complex	Corpus Christi, TX	18	15	83	%
Total Southwest		18	15	83	%
Total De-ethanization		198	104	54	%

(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) NGL throughput includes volumes from December 4, 2015 to December 31, 2015.

Natural Gas Gathering Systems

System	Location	Design Throughput Capacity (mmcf/d)	Natural Gas Throughput[(1)(2)] (mmcf/d)	Utilization of Design Capacity[(1)]	
Marcellus Shale:					
Keystone System	Butler County, PA	227	200	88	%
Houston System	Washington County, PA	917	689	75	%
Total Marcellus Shale		1,144	889	78	%
Utica Shale:					
Ohio Gathering System[(3)]	Harrison, Monroe, Belmont, Guernsey and Noble Counties, OH	1,291	743	61	%
Jefferson Gas System[(4)]	Jefferson County, OH	250	2	2	%
Total Utica Shale		1,541	745	57	%
Southwest					
East Texas System	Harrison and Panola Counties, TX	680	628	92	%
Western Oklahoma System	Wheeler County, TX and Roger Mills, Ellis, Custer, Beckham and Washita Counties, OK	585	333	57	%
Southeast Oklahoma System	Hughes, Pittsburg and Coal Counties, OK	1,265	432	34	%
Eagle Ford System	Dimmit County, TX	45	36	80	%
Other Systems[(5)]	Various	95	12	13	%

Total Southwest	2,670	1,441	54	%
Total Natural Gas Gathering	5,355	3,075	60	%

(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) Natural gas throughput includes volumes from December 4, 2015 to December 31, 2015.

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(3) The Ohio Gathering System is owned by Ohio Gathering. We account for Ohio Gathering as an equity method investment. See discussion in Item 8. Financial Statements and Supplementary Data - Note 5.

(4) 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.

(5) Excludes lateral pipelines where revenue is not based on throughput.

NGL Pipelines

Pipeline	Location	Design Throughput Capacity (mbpd)	NGL Throughput(1) (mbpd)	Utilization of Design Capacity	
Marcellus Shale:					
Sherwood to Mobley propane and heavier liquids pipeline	Doddridge County, WV to Wetzel County, WV	45	31	69	%
Mobley to Majorsville propane and heavier liquids pipeline	Wetzel County, WV to Marshall County, WV	80	22	28	%
Majorsville to Houston propane and heavier liquids pipeline	Marshall County, WV to Washington County, PA	47	42	89	%
Majorsville to Hopedale propane and heavier liquids pipeline	Marshall County, WV to Harrison County, OH	90	50	56	%
Third party processing plant to Keystone ethane and heavier liquids pipeline	Butler County, PA	32	7	22	%
Keystone to Mariner West ethane pipeline(2)	Butler County, PA to Beaver County, PA	35	10	29	%
Houston to Ohio River ethane pipeline(3)	Washington County, PA to Beaver County, PA	57	15	26	%
Majorsville to Houston ethane pipeline(2)	Marshall County, WV to Washington County, PA	60	50	83	%
Sherwood to Mobley ethane pipeline	Doddridge County, WV to Wetzel County, WV	27	9	33	%
Mobley to Fort Beeler ethane pipeline	Wetzel County, WV to Marshall County, WV	64	9	14	%
Fort Beeler to Majorsville ethane pipeline	Marshall County, WV	45	9	20	%
Utica Shale:					
Seneca to Hopedale liquids pipeline	Noble County, OH to Harrison County, OH	172	26	15	%
Appalachia:					
Langley to Siloam liquids pipeline(4)	Langley, KY to South Shore, KY	17	9	53	%
Southwest:					

East Texas liquids pipeline	Panola County, TX	39	27	69	%

(1) NGL throughput includes volumes from December 4, 2015 to December 31, 2015.
(2) This pipeline is FERC-regulated.
(3) This is a section of the Mariner West pipeline, which is FERC-regulated and is leased to and operated by Sunoco.
(4) 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.

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, 2015, NGL throughput on this pipeline was 9 mbpd, which was approximately 15 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, Keystone, 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 lease 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 20, 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.

In July 2015, a purported class action lawsuit asserting claims challenging the MarkWest Merger was filed in the Court of Chancery of the State of Delaware by a purported unitholder of MarkWest. In August 2015, two similar putative class action lawsuits were filed in the Court of Chancery of the State of Delaware by plaintiffs who purport to be unitholders of MarkWest. On September 9, 2015, these lawsuits were consolidated into one action pending in the Court of Chancery of the State of Delaware, now captioned In re MarkWest Energy Partners, L.P. Unitholder Litigation. On October 1, 2015, the plaintiffs filed a consolidated complaint against the individual members of the board of directors of MarkWest Energy GP, L.L.C. (the “MarkWest GP Board”), MPLX, MPLX GP, MPC and Sapphire Holdco LLC, a wholly-owned subsidiary of MPLX, asserting in connection with the MarkWest Merger and related disclosures that, among other things, (i) the MarkWest GP Board breached its duties in approving the MarkWest Merger with MPLX and (ii) MPC, MPLX, MPLX GP and Sapphire Holdco LLC aided and abetted such breaches. On February 4, 2016, the Court approved a stipulation and proposed order to dismiss all claims with

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prejudice as to the named plaintiffs, but for the Court to retain jurisdiction to adjudicate an application for a mootness fee by plaintiffs' counsel for an award of attorneys' fees and reimbursement of expenses. We intend to vigorously defend against any application for a mootness fee and do not expect the resolution of such matter to have a material adverse effect.

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. 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. 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 we are unable to estimate a reasonably possible loss (or range of loss) for this litigation. Under our omnibus agreement, MPC will indemnify us for the full cost of any losses should MPL be deemed responsible for any damages in this lawsuit.

Environmental Proceedings

On February 17, 2016, MarkWest Liberty Bluestone, L.L.C. ("MarkWest Liberty Bluestone"), received a Consent Agreement and Final Order ("CAFO") from the EPA alleging violations of the Clean Air Act resulting from an EPA compliance inspection conducted in July 2012 at our Sarsen Facility, a gas processing facility located in Pennsylvania. The alleged violations include the failure to comply with monitoring, tagging, recordkeeping and repair requirements with respect to certain pumps and/or valves at the facility. The alleged violations also include the failure to comply with certain emissions reduction and permit application requirements. The CAFO sets forth a proposed civil penalty of $285,078.

On July 6, 2015, officials from the EPA and the United States Department of Justice entered a MarkWest Liberty Midstream pipeline launcher/receiver site utilized for pipeline maintenance operations in Washington County, Pennsylvania pursuant to a search warrant issued by the United States District Court for the Western District of Pennsylvania. At the conclusion of the search, the governmental officials presented MarkWest Liberty Midstream with a subpoena to provide documents related to the design, construction, operation, maintenance, modification, inspection, assessment, repair of, and/or emissions from MarkWest Liberty Midstream's pipeline facilities located in Pennsylvania. MarkWest Liberty Midstream is providing information in response to the subpoena and related requests for information from the relevant agencies, and is in discussions with the relevant agencies regarding issues associated with the search and subpoena and its operations of, and any permit related obligations for, its pipeline facilities in the Southern Appalachia region. Immediately following the July 6, 2015 search, MarkWest Liberty Midstream commenced its own assessment of its operations of launcher/receiver facilities. MarkWest Liberty Midstream's review to date has determined that MarkWest Liberty Midstream's operations have been conducted in a manner fully protective of its employees and the public, and that other than potentially having to obtain minor source Clean Air Act permits at a relatively small number of individual sites, MarkWest Liberty has operated in substantial compliance with applicable laws and regulations. It is possible that, in connection with any potential civil or criminal enforcement action associated with this matter, MarkWest Liberty Midstream will incur material assessments, penalties or fines, incur material defense costs and expenses, be required to modify operations or construction activities which could increase operating costs and capital expenditures, or be subject to other obligations or restrictions that could restrict or prohibit our activities, any or all of which could adversely affect our results of operations, financial position or cash flows. The amount of any potential assessments, penalties, fines, restrictions, requirements, modifications, costs or expenses that may be incurred in connection with any potential enforcement action cannot be reasonably estimated at this time.

On March 21, 2014, MarkWest Liberty Midstream received a Draft Consent Order from the West Virginia Department of Environmental Protection ("WVDEP") incorporating 16 separate inspections in 2013 of various operations and construction sites with claimed regulatory violations relating to erosion and sediment control measures, damage in 2013 to a portion of the Marcellus NGL pipeline in Wetzel County, West Virginia which resulted from landslides and associated issues, pipeline borings and other disparate matters. The Draft Consent Order aggregated those matters and proposed a total aggregate administrative penalty of $115,120 for all of the various alleged claims, as well as the development of an approved remediation plan and certain provisions for approval of pipeline boring plans and other construction related activities in West Virginia going forward. MarkWest Liberty Midstream and WVDEP entered into a final Consent Order resolving all alleged violations, which became effective on November 2, 2015. Pursuant to the final Consent Order, MarkWest Liberty Midstream paid a penalty of $76,450 and submitted a corrective action plan to the WVDEP, and will periodically provide the WVDEP with information relating to slips impacting or having the potential to impact waters of the State of West Virginia.

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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

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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 12, 2016, there were 476 registered holders of 239,765,119 outstanding common units held by the public, including 230,904,841 common units held in street name. In addition, as of February 12, 2016, MPC and its affiliates owned 56,932,134 of our common units, and 6,800,681 of our general partner units which together constitutes a 20.4 percent ownership interest (excluding the Class A units owned by MarkWest Hydrocarbon, a wholly-owned subsidiary of the Partnership, and including the Class B units on an as-converted basis).

As part of the MarkWest Merger, we issued 1.09 MPLX common units for every one common unit of MarkWest. This resulted in 216,350,465 units issued. MarkWest had 7,981,756 Class B units outstanding, which converted into an equivalent number of MPLX Class B units on the date of the MarkWest Merger. These MPLX Class B units will convert into common units in two equal installments on July 1, 2016 and July 1, 2017, based on a conversion ratio of 1.09 common units for each Class B unit and $6.20 in cash for each Class B unit. MPC will fund this cash payment.

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.

	Trading prices per common unit				
Quarter ended	High	Low	Quarterly cash distribution per unit (1)	Distribution date	Record date
December 31, 2015	$45.63	$26.38	$0.5000	February 12, 2016	February 4, 2016
September 30, 2015	71.73	35.55	0.4700	November 13, 2015	November 3, 2015
June 30, 2015	80.00	70.23	0.4400	August 14, 2015	August 4, 2015
March 31, 2015	85.57	65.29	0.4100	May 15, 2015	May 5, 2015
December 31, 2014	73.76	46.08	0.3825	February 13, 2015	February 3, 2015
September 30, 2014	68.05	55.00	0.3575	November 14, 2014	November 4, 2014
June 30, 2014	66.49	48.14	0.3425	August 14, 2014	August 4, 2014
March 31, 2014	50.75	40.01	0.3275	May 15, 2014	May 5, 2014

(1) Represents cash distributions attributable to the quarter and declared and paid in accordance with our partnership agreement.

We intend to pay a minimum quarterly distribution of $0.2625 per unit. Although our partnership agreement requires that we distribute all of our available cash each quarter, we do not have a legal obligation to distribute any particular amount per common unit.

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. Class B unitholders do not receive cash distributions. Class A unitholders receive distributions of available cash (excluding the available cash attributable to MarkWest Hydrocarbon). However, because all Class A unitholders are wholly-owned subsidiaries, these intercompany distributions do not impact the amount of available cash that can be distributed to common unitholders.

Definition of available cash. Available cash is defined in our partnership agreement, which is an exhibit to this Annual Report on Form 10-K. 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, anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law subsequent to that quarter);

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- comply with applicable law, any of our debt instruments or other agreements; 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 and any cumulative arrearages on such common units for the current quarter);
- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter 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 and subordinated 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.

General Partner Interest and Incentive Distribution Rights. Our general partner is currently entitled to two percent of all quarterly distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's two percent interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its two percent general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 48 percent, of the cash we distribute from operating surplus in excess of $0.301875 per unit per quarter. The maximum distribution of 48 percent does not include any distributions that our general partner or its affiliates may receive on common, subordinated or general partner units that they own. While the Class A units are held by one of our wholly-owned subsidiaries, the calculation of the amount of available cash payable to our general partner pursuant to the incentive distribution rights will exclude the available cash payable on the Class A units.

Percentage Allocations of Available Cash. The following table illustrates the percentage allocations of available cash from operating surplus between the common unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal percentage interest in distributions" are the percentage interests of our general partner and the common unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total quarterly distribution per unit target amount." The percentage interests shown for our common unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its two percent general partner interest and assume that our general partner has contributed any additional capital necessary to maintain its two percent general partner interest, that our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total quarterly distribution per unit target amount		Marginal percentage interest in distributions			
			Unitholders[(1)]		General Partner	
Minimum Quarterly Distribution	$0.2625		98.0	%	2.0	%
First Target Distribution	above $0.2625	up to $0.301875	98.0	%	2.0	%
Second Target Distribution	above $0.301875	up to $0.328125	85.0	%	15.0	%
Third Target Distribution	above $0.328125	up to $0.393750	75.0	%	25.0	%

Thereafter	above $0.393750	50.0 %	50.0 %

(1) The unitholders’ percentage of distributions is paid to common unitholders, subordinated unitholders, if any, and Class A unitholders on a pro rata basis except that Class A units will not be entitled to participate in any distributions of available cash derived from or attributable to MPLX LP’s ownership interest of MarkWest Hydrocarbon or the disposition of such interest.

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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 our 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.

Recent Sales of Unregistered Units

We issued approximately 29 million MPLX Class A units to MarkWest Hydrocarbon as part of the MarkWest Merger. MarkWest Hydrocarbon is our wholly-owned subsidiary and therefore the Class A units are eliminated in consolidation. We issued approximately eight million Class B units to M&R MWE Liberty, LLC, an affiliate of EMG, as part of the MarkWest Merger. MarkWest issued the MarkWest Class B units as part of their acquisition of the noncontrolling interest in MarkWest Liberty Midstream, which was effective December 31, 2011.

See Item 1. Business - Organizational Structure for further discussion of the Class A and Class B units.

In connection with the above issuances of units, our general partner elected to maintain its two percent interest and purchased general partner units. 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.

Repurchase of Equity by MPLX LP

None

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Item 6. Selected Financial Data

The following table shows selected historical consolidated financial data of MPLX LP and MPLX LP Predecessor ("Predecessor"), our predecessor for accounting purposes, as of the dates and for the years indicated. Our Predecessor consisted of a 100 percent interest in all of the assets and operations of MPL and ORPL that MPC contributed to us at the closing of the Initial Offering, as well as minority undivided joint interests in two crude oil pipeline systems (the "Joint Interest Assets") that were not contributed to us. In connection with the closing of the Initial Offering, MPC transferred the Joint Interest Assets from our Predecessor to other MPC subsidiaries and then contributed to us a 51 percent indirect ownership interest in Pipe Line Holdings, which owns our Predecessor's assets and operations (other than the Joint Interest Assets), and a 100 percent indirect ownership in our butane cavern. 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. See Item 8. Financial Statements and Supplementary Data - Note 4 and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for more information on the MarkWest Merger. In addition, we recorded the contributions at historical cost, as they are considered transactions between entities under common control.

The selected historical consolidated financial data as of and for the year ended December 31, 2011 were derived from audited combined financial statements of our Predecessor.

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.

(In millions, except per unit data)	2015	2014	2013	2012	2011
Consolidated Statements of Income data:					
Service revenue	$150	$69	$79	$74	$62
Service revenue to related parties	481	451	384	368	335
Product sales	36	—	—	—	—
Product sales to related parties	1	—	—	—	—
Other income	8	5	4	7	5
Other income - related parties	27	23	19	13	9
Total revenues and other income	703	548	486	462	411
Total costs and expenses	497	365	339	319	279
Income from operations	$206	$183	$147	$143	$132
Net income	$157	$178	$146	$144	$134
Net income attributable to MPLX LP	156	121	78	131	134
Net income attributable to MPLX LP subsequent to the Initial Offering	156	121	78	13	
Limited partners' interest in net income attributable to MPLX LP	99	115	76	13	
Net income attributable to MPLX LP per limited partner unit (basic and diluted):					
Common - basic	$1.23	$1.55	$1.05	$0.18	
Common - diluted	1.22	1.55	1.05	0.18	
Subordinated - basic and diluted	0.11	1.50	1.01	0.17	
Cash distributions declared per limited partner common unit	$1.8200	$1.4100	$1.1675	$0.1769	
Consolidated Balance Sheets data (at period end):					

Property, plant and equipment, net	$9,683	$1,008	$967	$910	$867
Total assets	15,677	1,214	1,209	1,301	1,303
Long-term debt, including capital leases	5,255	644	10	10	11
Consolidated Statements of Cash Flows data:					
Net cash provided by (used in):					
Operating activities	$239	$247	$212	$191	$182
Investing activities	(1,498)	(75)	(114)	87	(219)
Financing activities	1,275	(199)	(261)	(61)	37
Additions to property, plant and equipment[1]	264	79	107	136	50
Other financial data[2]:					
Adjusted EBITDA attributable to MPLX LP[3]	486	166	111	18	
DCF attributable to MPLX LP[3]	399	137	114	17	

(1) 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.

(2) 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) The 2012 Adjusted EBITDA attributable to MPLX LP is subsequent to the Initial Offering. The 2015 Adjusted EBITDA attributable to MPLX LP includes pre-merger EBITDA from MarkWest and the 2015 DCF attributable to MPLX LP includes undistributed DCF from MarkWest. See Item 7. Management's Discussion and Analysis - Results of Operations for a reconciliation of non-GAAP measures.

Operating Data

	2015	2014	2013	2012	2011
L&S					
Crude oil transported for (mbpd)[1]:					
MPC	864	838	853	830	811
Third parties	197	203	222	202	182
Total	1,061	1,041	1,075	1,032	993
% MPC	81 %	80 %	79 %	80 %	82 %
Products transported for (mbpd)[2]:					
MPC[3]	887	852	862	909	971
Third parties	27	26	49	71	60
Total	914	878	911	980	1,031
% MPC	97 %	97 %	95 %	93 %	94 %
Average tariff rates ($ per barrel):					
Crude oil pipelines	0.66	0.64	0.60	0.57	0.40
Product pipelines	0.65	0.61	0.56	0.51	0.44
Total pipelines	0.65	0.63	0.58	0.54	0.42
G&P[4]					
Gathering Throughput (mmcf/d)					
Marcellus operations	889				
Utica operations[5][6]	745				

Southwest operations[7]	1,441
Total gathering throughput	3,075
Natural Gas Processed (mmcf/d)	
Marcellus operations	2,964
Utica operations[5]	1,136
Southwest operations	1,125
Southern Appalachian operations	243
Total natural gas processed	5,468
C2 + NGLs Fractionated (mbpd)	
Marcellus operations[8][9]	220
Utica operations[5][9]	51
Southwest operations	24
Southern Appalachian operations[10]	12
Total C2 + NGLs fractionated[11]	307
Pricing Information	
Natural Gas NYMEX HH ($/MMBtu)	$2.04
C2 + NGL Pricing/gallon[12]	$0.40

(1) Represents the average aggregate daily number of barrels of crude oil transported on our pipeline systems and at our Wood River barge dock for MPC and for third parties. Volumes shown are 100 percent of the volumes transported on the pipeline systems and barge dock. Volumes shown for all periods exclude volumes transported on two undivided joint interest crude oil pipeline systems not contributed to MPLX LP at the Initial Offering.

(2) Represents the average aggregate daily number of barrels of products transported on our pipeline systems for MPC and third parties. Volumes shown are 100 percent of the volumes transported on the pipeline systems.

(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) G&P volumes represent the volumes after the close of the MarkWest Merger. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for full year pro-forma information.

(5) Utica is an unconsolidated equity method investment and is consolidated for segment purposes only.

(6) The Jefferson Gas System came online in December 2015. The volumes reported for 2015 are the average daily rate for the days of operation.

(7) Includes approximately 310 mmcf/d related to unconsolidated equity method investments, Wirth and MarkWest Pioneer.

(8) The Sherwood de-ethanization complex came online in December 2015. The volumes reported for 2015 are the average daily rate for the days of operation.

(9) Hopedale is jointly owned by MarkWest Liberty Midstream and MarkWest Utica EMG, 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.

(10) Includes NGLs fractionated for the Marcellus and Utica operations.

(11) Purity ethane makes up approximately 104 mbpd of total fractionated products.

(12) 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.

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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," "int "plan," "predict," "project," "potential," "seek," "target," "could," "may," "should," "would," "will," or other similar expressio 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

Significant financial and other highlights for the year ended December 31, 2015 are listed below. Refer to Results of Operations and Liquidity and Capital Resources for further details.

- On December 4, 2015, we completed the MarkWest Merger. MarkWest is now a wholly-owned subsidiary of MPLX LP. See Item 8. Financial Statements and Supplementary Data - Note 4 for more information.
- Total segment operating income attributable to MPLX LP increased approximately $185 million, or 87 percent, in 2015 compared to 2014. The increase was comprised of the following:
  - An increase of approximately $84 million in our L&S segment is primarily due to the acquisition of the remaining interest in Pipe Line Holdings.
  - An increase of approximately $76 million in our G&P segment is due to the MarkWest Merger.
- The offer to exchange MarkWest senior notes for MPLX senior notes and cash expired in December 2015. Approximately $4.0 billion aggregate principal amount of MarkWest senior notes were exchanged for MPLX senior notes. We incurred approximately $16 million of expenses related to this exchange.
- On October 27, 2015, in connection with the MarkWest Merger, we amended our $1.0 billion bank revolving credit facility to, among other things, (i) extend the term of the bank revolving credit facility to a five-year term commencing on the date of the closing of the MarkWest Merger and (ii) increase the borrowing capacity of the bank revolving credit facility to up to $2.0 billion. The amendment became effective in connection with the MarkWest Merger.
- In December 2015, we purchased the remaining 0.5 percent interest in Pipe Line Holdings from MPC for $12 million.
- During the third quarter of 2015, the requirements for the conversion of all subordinated units were satisfied under the partnership agreement. Effective August 17, 2015, 36,951,515 subordinated units owned by MPC were converted into common units on a one-for-one basis and prospectively participate on terms equal with all other common units in distributions of available cash. The conversion did not impact the amount of cash distributions paid by the Partnership or total units outstanding.
- On February 12, 2015, we completed an underwritten public offering of $500 million aggregate principal amount of four percent unsecured senior notes due February 15, 2025 (the "Senior Notes"). The Senior Notes were offered at a price to the public of 99.64 percent of par. The net proceeds of this offering were used to repay the amounts outstanding under our bank revolving credit facility, as well as for general partnership purposes.

In connection with the MarkWest Merger, we recorded approximately $2.5 billion of goodwill. Goodwill is not amortized, but rather is tested for impairment annually or more frequently if warranted due to events or changes in circumstances. See Critical Accounting Estimates - Impairment Assessments of Long-Lived Assets, Intangible Assets, Goodwill and Equity Investments for discussion of recent circumstances that may impact the assessment of goodwill impairment.

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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.

We define Adjusted EBITDA as net income adjusted for (i) depreciation and amortization; (ii) provision for income taxes; (iii)non-cash equity-based compensation; (iv) net interest and other financial costs; (v) equity investment income; (vi) equity method distributions; and (vii) acquisition costs. We also use DCF, which we define as Adjusted EBITDA plus (i) the current period cash received/deferred revenue for committed volume deficiencies less (iii) net interest and other financial costs; (iv) unrealized gain on commodity hedges; (v) equity investment capital expenditures paid out; (vi) equity investment cash contributions; (vii) maintenance capital expenditures paid; (viii) volume deficiency credits recognized; and (ix) other non-cash items.

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 as 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 any derivative gain (loss). 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. These financial measures are presented in Item 8. Financial Statements and Supplementary Data - Note 9 and are considered non-GAAP financial measures when presented outside of the Notes to the Consolidated Financial Statements. 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 9 for the reconciliations of these segment measures, including total segment operating income to their respective most directly comparable GAAP measure.

COMPARABILITY OF OUR FINANCIAL RESULTS

Our acquisitions have impacted comparability of our financial results (see Item 8. Financial Statements and Supplementary Data - Note 4).

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RESULTS OF OPERATIONS

	Year Ended December 31,				
(In millions)	2015	2014	$ Change	2013	$ Change
Revenues and other income:					
Service revenue	$150	$69	$81	$79	$(10)
Service revenue to related parties	481	451	30	384	67
Product sales	36	—	36	—	—
Product sales to related parties	1	—	1	—	—
Other income	8	5	3	4	1
Other income - related parties	27	23	4	19	4
Total revenues and other income	703	548	155	486	62
Costs and expenses:					
Cost of revenues (excludes items below)	172	145	27	136	9
Purchased product costs	20	—	20	—	—
Purchases from related parties	102	98	4	95	3
Depreciation and amortization	89	50	39	49	1
General and administrative expenses	104	65	39	53	12
Other taxes	10	7	3	6	1
Total costs and expenses	497	365	132	339	26
Income from operations	206	183	23	147	36
Interest expense (net of amounts capitalized of $5 million, $1 million and $1 million, respectively)	35	4	31	—	4
Other financial costs	12	1	11	1	—
Income before income taxes	159	178	(19)	146	32
Provision for income taxes	2	—	2	—	—
Net income	157	178	(21)	146	32
Less: Net income attributable to noncontrolling interests	1	57	(56)	68	(11)
Net income attributable to MPLX LP	$156	$121	$35	$78	$43
Adjusted EBITDA attributable to MPLX LP[(1)]	$486	$166	$320	$111	$55
DCF attributable to MPLX LP[(1)]	399	137	262	114	23

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

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The following tables present a reconciliation of Adjusted EBITDA and DCF to net income and net cash provided by operating activities, the most directly comparable GAAP financial measures. Items from Adjusted EBITDA attributable to MPLX LP to DCF attributable to MPLX LP are shown net of noncontrolling interest.

(In millions)	2015	2014	2013
Reconciliation of Adjusted EBITDA attributable to MPLX LP and DCF attributable to MPLX LP from Net Income:			
Net income	$157	$178	$146
Plus: Depreciation and amortization	89	50	49
Provision for income taxes	2	—	—
Non-cash equity-based compensation	4	2	1
Net interest and other financial costs	47	5	1
Income from equity investments	(3)	—	—
Distributions from unconsolidated subsidiaries	15	—	—
Acquisition costs	30	—	—
Adjusted EBITDA	341	235	197
Less: Adjusted EBITDA attributable to noncontrolling interests	1	69	86
MarkWest's pre-merger EBITDA [(1)]	146	—	—
Adjusted EBITDA attributable to MPLX LP	486	166	111
Plus: Current period cash received/deferred revenue for committed volume deficiencies	44	31	19
Less: Net interest and other financial costs	36	6	2
Unrealized gain on commodity hedges	4	—	—
Equity investment capital expenditures paid out	(14)	—	—
Investment in unconsolidated affiliates	14	—	—
Maintenance capital expenditures paid	30	20	12
Volume deficiency credits recognized	38	34	2
Other	7	—	—
DCF pre-MarkWest undistributed	415	137	114
MarkWest undistributed DCF[(1)]	(16)	—	—
DCF attributable to MPLX LP	$399	$137	$114

(1) MarkWest pre-merger EBITDA and undistributed DCF relates to MarkWest's EBITDA and DCF from Oct. 1, 2015, through Dec. 3, 2015.

(In millions)	2015	2014	2013
Reconciliation of Adjusted EBITDA attributable to MPLX LP and DCF attributable to MPLX LP from Net Cash Provided by Operating Activities:			
Net cash provided by operating activities	$239	$247	$212
Less: Changes in working capital items	(38)	19	22
All other, net	17	2	3
Plus: Non-cash equity-based compensation	4	2	1
Net loss on disposal of assets	(1)	—	—
Net interest and other financial costs	47	5	1
Asset retirement expenditures	1	2	8
Acquisition costs	30	—	—
Adjusted EBITDA	341	235	197
Less: Adjusted EBITDA attributable to MPC-retained interest	1	69	86
MarkWest's pre-merger EBITDA [(1)]	146	—	—
Adjusted EBITDA attributable to MPLX LP	486	166	111
	44	31	19

Plus: Current period cash received/deferred revenue for committed volume deficiencies			
Less: Net interest and other financial costs	36	6	2
Unrealized gain on commodity hedges	4	—	—
Equity investment capital expenditures paid out	(14)	—	—
Equity investment cash contributions	14	—	—
Maintenance capital expenditures paid	30	20	12
Volume deficiency credits recognized	38	34	2
Other	7	—	—
DCF pre-MarkWest undistributed	415	137	114
MarkWest undistributed DCF[1]	(16)	—	—
DCF attributable to MPLX LP	$399	$137	$114

(1) MarkWest pre-merger EBITDA and undistributed DCF relates to MarkWest's EBITDA and DCF from Oct. 1, 2015, through Dec. 3, 2015.

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

(In millions)	2015	2014	2013
Reconciliation of net operating margin to income from operations:			
Segment revenue	$697	$520	$463
Purchased product costs	20	—	—
Less: Unrealized derivative gain related to purchased product costs	5	—	—
Less: Realized derivative gain related to revenues and purchased product costs	4	—	—
Net operating margin	668	520	463
Revenue adjustment from unconsolidated affiliates[1]	(28)	—	—
Realized derivative gain related to revenues and purchased product costs	4	—	—
Total unrealized derivative gain	4	—	—
Other income	8	5	4
Other income - related parties	27	23	19
Cost of revenues (excludes items below)	(172)	(145)	(136)
Purchases from related parties	(102)	(98)	(95)
Depreciation and amortization	(89)	(50)	(49)
General and administrative expenses	(104)	(65)	(53)
Other taxes	(10)	(7)	(6)
Income from operations	$206	$183	$147

(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 operate and manage the operations. Therefore, the impact of the revenue is included for segment reporting purposes, but removed for GAAP purposes.

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2015 Compared to 2014

Service revenue increased $81 million in 2015 compared to 2014. This variance was primarily due to an $83 million increase in the G&P segment from the MarkWest Merger and a $2 million increase resulting from higher average tariffs received on the volumes of crude oil and products shipped, partially offset by a $5 million decrease related to a 13 mbpd reduction in third-party crude oil and products volumes shipped.

Service revenue to related parties increased $30 million in 2015 compared to 2014. This increase was primarily related to a $32 million increase due to higher average tariffs received on the volumes of crude oil and products shipped and a $3 million increase in storage fees and other revenue related to the expansion of the Patoka Tank Farms, partially offset by a $7 million decrease in revenue related to volume deficiency credits recognized.

Product sales increased $36 million in 2015 compared to 2014. This variance was primarily due to the MarkWest Merger.

Other income and other income - related parties increased a total of $7 million in 2015 compared to 2014. The increase was primarily due to an increase in fees received for operating MPC's private pipeline systems and an increase due to the MarkWest Merger.

Cost of revenues increased $27 million in 2015 compared to 2014. The increase was primarily due to the MarkWest Merger.

Purchased product costs increased $20 million in 2015 compared to 2014. This variance was primarily due to the MarkWest Merger.

Purchases from related parties increased $4 million in 2015 compared to 2014. The increase was primarily due to higher compensation expenses provided under the omnibus and employee services agreements with MPC, partially offset by increased capitalization of employee costs associated with capital projects.

Depreciation and amortization expense increased $39 million in 2015 compared to 2014 primarily due to the MarkWest Merger.

General and administrative expenses increased $39 million in 2015 compared to 2014. The increase in 2015 was primarily related to $30 million in acquisition costs.

Other taxes increased $3 million in 2015 compared to 2014. The increase was primarily due to property taxes from the MarkWest Merger.

Interest expense and other financial costs increased $42 million in 2015 compared to 2014. The increase was due to borrowings on the bank revolving credit facility, term loan and senior notes in connection with the MarkWest Merger. The increase was also due to $6 million in transaction costs related to the exchange of MarkWest senior notes for MPLX senior notes.

During 2015 and 2014, MPC did not ship its minimum committed volumes on certain of our pipeline systems. As a result, MPC was obligated to make $44 million and $41 million of deficiency payments in 2015 and 2014, respectively. We record deficiency payments as Deferred revenue - related parties on our Consolidated Balance Sheets. During 2015 and 2014, we recognized revenue of $38 million and $45 million, respectively, related to volume deficiency credits. At December 31, 2015 and 2014, the cumulative balance of Deferred revenue - related parties on our Consolidated Balance Sheets related to volume deficiencies was $36 million and $30 million, respectively. The following table presents the future expiration dates of the associated deferred revenue credits for 2015:

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(In millions)	
March 31, 2016	$7
June 30, 2016	5
September 30, 2016	9
December 31, 2016	10
March 31, 2017	2
June 30, 2017	1
September 30, 2017	1
December 31, 2017	1
Total	$36

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 and when it becomes impossible to physically transport volumes necessary to utilize the accumulated credits or upon expiration of the make-up period. However, deficiency payments are included in the determination of DCF in the period in which a deficiency occurs since the cash has been received.

2014 Compared to 2013

Service revenue decreased $10 million in 2014 compared to 2013. This variance was primarily due to a $14 million decrease related to a 47 mbpd reduction in third-party crude oil and products volumes shipped, offset by a $4 million increase resulting from higher average tariffs received on the volumes of crude oil and products shipped.

Service revenue to related parties increased $67 million in 2014 compared to 2013. This increase was primarily related to a $40 million increase in revenue related to volume deficiency credits and $25 million due to higher average tariffs received on the volumes of crude oil and products shipped.

Other income and other income - related parties increased a total of $5 million in 2014 compared to 2013. The net increase was primarily due to an increase in fees received for operating MPC’s private pipeline systems.

Cost of revenues increased $9 million in 2014 compared to 2013. The increase was primarily due to an increase in contract services used for maintenance activities.

Purchases from related parties increased $3 million in 2014 compared to 2013. The increase was primarily due to higher compensation expenses provided under the omnibus and employee services agreements with MPC.

Depreciation and amortization expense increased $1 million in 2014 compared to 2013 due to the completion of various capital projects.

General and administrative expenses increased $12 million in 2014 compared to 2013. The increase in 2014 is primarily related to services provided under the omnibus and employee services agreements with MPC and increased consulting fees related to the acquisitions in 2014.

Other taxes increased $1 million in 2014 compared to 2013. The increase was primarily due to increased property taxes from investment activities in 2014.

Interest expense and other financial costs increased $4 million in 2014 compared to 2013. The increase was due to borrowings on the bank revolving credit facility and new term loan in 2014.

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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 gains (losses) and depreciation 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.

The tables below present information about segment operating income for the reported segments for the years ended December 31, 2015 and 2014. For information for the year ended December 31, 2013, see Results of Operations.

L&S Segment

(In millions)	2015	2014	$ Change	% Change
Revenues and other income:				
Segment revenue	$547	$520	$27	5 %
Segment other income	30	28	2	7 %
Total segment revenues and other income	577	548	29	5 %
Costs and expenses:				
Segment cost of revenues	254	250	4	2 %
Segment operating income before portion attributable to noncontrolling interest	323	298	25	8 %
Segment portion attributable to noncontrolling interest	1	85	(84)	(99)%
Segment operating income attributable to MPLX LP	$322	$213	$109	51 %

Segment revenue increased due to a $34 million increase in higher average tariffs received on the volumes of crude oil and products shipped, partially offset by a $7 million decrease in revenue related to volume deficiency credits recognized.

Segment other income increased due to an increase in storage fees and other revenue related to the expansion of the Patoka Tank Farms.

Segment cost of revenues increased primarily due to higher compensation expenses provided under the omnibus and employee services agreements with MPC, partially offset by increased capitalization of employee costs associated with capital projects.

Segment portion attributable to noncontrolling interest decreased due to the acquisition of the remaining interest of Pipe Line Holdings, of which the 0.5 percent was purchased on December 4, 2015.

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G&P Segment

(In millions)	2015	2014	$ Change	% Change
Revenues and other income:				
Segment revenue	$150	$—	$150	— %
Segment other income	—	—	—	— %
Total segment revenues and other income	150	—	150	— %
Costs and expenses:				
Segment cost of revenues	62	—	62	— %
Segment operating income before portion attributable to noncontrolling interest	88	—	88	— %
Segment portion attributable to noncontrolling interest	12	—	12	— %
Segment operating income attributable to MPLX LP	$76	$—	$76	— %

The G&P segment increased overall due to the MarkWest Merger.

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 interest to our consolidated net income attributable to noncontrolling interests for the years ended December 31, 2015 and 2014.

(In millions)	2015	2014
Reconciliation to Income from operations:		
L&S segment operating income attributable to MPLX	$322	$213
G&P segment operating income attributable to MPLX	76	—
Segment operating income attributable to MPLX	398	213
Segment portion attributable to unconsolidated affiliates	(21)	—
Segment portion attributable to noncontrolling interest	13	85
Income from equity method investments	3	—
Other income - related parties	2	—
Unrealized derivative gains	4	—
Depreciation and amortization	(89)	(50)
General and administrative expenses	(104)	(65)
Income from operations	$206	$183

(In millions)	2015	2014
Reconciliation to Total revenues and other income:		
Total segment revenues and other income	$727	$548
Revenue adjustment from unconsolidated affiliates	(28)	—
Income from equity method investments	3	—
Other income - related parties	2	—
Unrealized derivative loss	(1)	—
Total revenues and other income	$703	$548

(in millions)	2015	2014
Reconciliation to Net income attributable to noncontrolling interests		
Segment portion attributable to noncontrolling interest	$13	$85
Portion of noncontrolling interests related to items below segment income from operations	(7)	(28)
Portion of operating income attributable to noncontrolling interests of unconsolidated affiliates	(5)	—
Net income attributable to noncontrolling interests	$1	$57

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SUPPLEMENTAL MD&A - G&P PRO FORMA

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2015 and 2014. This is a supplemental disclosure showing G&P segment results as if it were acquired as of January 1, 2014 and it incorporates pro forma adjustments necessary, including the removal of approximately $90 million of transaction costs, to reflect a January 1, 2014 acquisition date (see reconciliations below). The pro forma information was prepared in a manner consistent with Article 11 of Regulation S-X and FASB ASC Topic 805 (see Item 8. Financial Statements and Supplementary Data - Note 4). We believe this full year data will provide a more meaningful discussion of trends for the G&P segment as it helps convey the impact of commodity pricing and volume changes to the business. Future results may vary significantly from the results reflected below because of various factors. In addition, all Partnership operated, non-wholly owned subsidiaries are treated as if they are consolidated for segment reporting purposes (for more information on how management has determined our segments see Item 8. Financial Statements and Supplementary Data - Note 9).

(In millions)	2015	2014	$ Change	% Change
Revenues and other income:				
Segment revenue	$2,151	$2,168	$(17)	(1)%
Total segment revenues and other income	2,151	2,168	(17)	(1)%
Costs and expenses:				
Segment cost of revenues	903	1,197	(294)	(25)%
Segment operating income before portion attributable to noncontrolling interest	1,248	971	277	29%
Segment portion attributable to noncontrolling interest	156	36	120	333%
Segment operating income attributable to MPLX LP	$1,092	$935	$157	17%

Segment revenue decreased due to a 39 percent decrease in natural gas prices and a 50 percent decrease in NGL prices over the same period in 2014. There was a $151 million decrease in inventory sold compared to the same period in 2014 due to changes in contractual terms. This decrease was partially offset by an increase in volumes. Total gathering throughput, total natural gas processed and total C2+ NGLs fractionated volumes increased by 28 percent, 36 percent and 30 percent, respectively.

Segment cost of revenues decreased mainly due to a decrease of $152 million in inventory sold compared to the same period in 2014 due to changes in contractual terms and decreases in natural gas purchased prices and NGL prices. Segment cost of revenues as a percentage of segment revenue decreased 13 percent for the year ended December 31, 2015 compared to the same period in 2014. This decrease was primarily due to an increase in fee revenue as a percent of total revenue by 16%. The decreases were partially offset by increased expenses related to the expansion of Utica and Marcellus operations.

The change in the segment portion of operating income attributable to noncontrolling interests increased due to ongoing growth in our entities that are not wholly owned.

Reconciliation of Segment Operating Income to Consolidated Income Before Provision for Income Tax

The following tables provide reconciliations of G&P’s segment operating income attributable to MPLX LP to G&P income from operations, G&P segment revenues and other income to G&P total revenues and other income, and G&P segment portion attributable to noncontrolling interests for the years ended December 31, 2015 and 2014, respectively. The ensuing items listed below the Other income - related parties lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

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(In millions)	2015	2014
Pro forma reconciliation to total revenues and other income:		
Total G&P segment revenues and other income	2,151	2,168
Revenue adjustment from unconsolidated affiliates	(303)	(41)
Income (loss) from equity method investments	13	(12)
G&P Other income - related parties	(4)	19
Unrealized derivative (losses) gains related to revenue	(10)	25
Total pro forma G&P revenues and other income	$1,847	$2,159
Total pro forma L&S revenues and other income	577	548
Total pro forma revenues and other income	$2,424	$2,707

(In millions)	2015	2014
Pro Forma reconciliation to pro forma net income attributable to MPLX LP:		
Segment operating income attributable to G&P	$1,092	$935
G&P Segment portion attributable to unconsolidated affiliates	(101)	(8)
G&P Segment portion attributable to noncontrolling interest	38	21
G&P Income (loss) from equity method investments	13	(12)
G&P Other income - related parties	(4)	19
Unrealized derivative (losses) gains	(10)	82
Impairment expense	(26)	(62)
G&P Depreciation	(500)	(481)
G&P General and administrative expenses	(125)	(130)
Pro forma G&P income from operations	$377	$364
Pro forma L&S income from operations	200	184
Pro forma income from operations	577	548
G&P Debt retirement expense	118	—
Net interest and other financial costs	259	189
Pro forma income before income taxes	200	359
Provision (benefit) for income taxes	(9)	45
Pro forma net income	209	314
Less: Net income attributable to noncontrolling interests	55	66
Pro forma net income attributable to MPLX LP	$154	$248

Pro Forma Operating Statistics	2015	2014	% Change	
Gathering Throughput (mmcf/d)				
Marcellus operations	858	668	28	%
Utica operations[1]	673	289	133	%
Southwest operations[2]	1,413	1,336	6	%
Total gathering throughput	2,944	2,293	28	%
Natural Gas Processed (mmcf/d)				
Marcellus operations	2,861	2,064	39	%
Utica operations[1]	883	416	112	%
Southwest operations	1,077	991	9	%
Southern Appalachian operations	267	280	(5	)%
Total natural gas processed	5,088	3,751	36	%
C2 + NGLs Fractionated (mbpd)				
Marcellus operations[3][4]	194	147	32	%
Utica operations[1][4]	40	19	111	%
Southwest operations	18	21	(14	)%
Southern Appalachian operations[5]	15	19	(21	)%
Total C2 + NGLs fractionated[6]	267	206	30	%
Pricing Information				
Natural Gas NYMEX HH ($/MMBtu)	$2.63	$4.28	(39	)%
C2 + NGL Pricing/gallon[7]	$0.46	$0.92	(50	)%

(1) Utica is an unconsolidated equity method investment and is consolidated for segment purposes only.

(2) Includes approximately 242 mmcf/d and 228 mmcf/d related to unconsolidated equity method investments, Wirth and MarkWest Pioneer, for the years ended December 31, 2015 and December 31, 2014, respectively.

(3) The Keystone ethane fractionation complex began operations in June 2014. The volumes reported for 2014 are the average daily rate for the days of operation.

(4) Hopedale is jointly owned by MarkWest Liberty Midstream and MarkWest Utica EMG, 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. Operations began in January 2014 and December 2014. The volumes reported for 2014 are the average daily rate for the days of operation.

(5) Includes NGLs fractionated for the Marcellus and Utica operations.

(6) Purity ethane makes up approximately 79 mbpd and 67 mbpd of total fractionated products for the years ended December 31, 2015 and December 31, 2014, respectively.

(7) C2 + NGL pricing based on Mont Belvieu prices assuming an NGL barrel of approximately 35 percent ethane, 35 percent propane, 6 percent Iso-Butane, 12 percent normal butane and 12 percent natural gasoline.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Our cash and cash equivalents balance was $43 million at December 31, 2015 compared to $27 million at December 31, 2014. 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:

(In millions)	2015	2014	2013
Net cash provided by (used in):			
Operating activities	$239	$247	$212
Investing activities	(1,498)	(75)	(114)
Financing activities	1,275	(199)	(261)
Total	$16	$(27)	$(163)

Cash Flows Provided by Operating Activities. Net cash provided by operating activities decreased $8 million in 2015 compared to 2014, primarily due to a $21 million decrease in net income and a $57 million unfavorable impact from changes in working capital as discussed below, partially offset by a $15 million increase in all other, net.

For 2015, changes in working capital were a net $38 million use of cash. Third-party receivables were a $29 million use of cash primarily due to higher third-party tariff revenue receivables. Net liabilities to related parties were an $8 million use of cash. Third-party accounts payables and liabilities were a $4 million source of cash due to the timing of project expenditures.

For 2014, changes in working capital were a net $19 million source of cash, primarily due to an increase in net liabilities to related parties and a decrease in third-party receivables. Net liabilities to related parties increased $15 million from 2013, primarily due to an increase in payables to related parties under the omnibus and employee services agreements and a decrease in receivables from related parties. Third-party receivables decreased $2 million primarily associated with lower tariff revenue receivables from lower product volumes shipped and timing of collections.

For 2013, changes in working capital were a net $22 million source of cash, primarily due to an increase in net liabilities to related parties and a decrease in third-party receivables. Net liabilities to related parties increased $19 million from 2012, primarily due to an increase in deferred revenue associated with deficiency payments, partially offset by an increase in receivables from related parties. Third-party receivables decreased $5 million primarily due to lower tariff revenue receivables from lower product volumes shipped.

Cash Flows Used in Investing Activities. Net cash used in investing activities increased $1.4 billion in 2015 compared to 2014, primarily due to $1.2 billion increase in acquisitions due to the MarkWest Merger and $185 million increase in additions to property, plant and equipment.

Net cash used in investing activities decreased $39 million in 2014 compared to 2013, primarily due to a $28 million decrease in additions to property, plant and equipment. Cash used for additions to property, plant and equipment were $79 million in 2014 and $107 million in 2013. The reduction was primarily associated with lower expansion capital expenditures in 2014.

Cash Flows from Financing Activities. Net cash provided by financing activities in 2015 was $1.3 billion compared to net cash used in 2014 of $199 million. The source of cash in 2015 was primarily due to $1.2 billion of contributions from MPC for the MarkWest Merger, $38 million in increased net long-term debt borrowings, $8 million in net proceeds from related party debt with MPC and $169 million in net proceeds from MPLX GP in exchange for a number of general partnership units that allowed it to maintain its general partnership interest, partially offset by $159 million in distributions to unitholders, general partner and noncontrolling interests. The use of cash in 2014 was primarily due to $910 million in distributions to MPC related to the acquisition of an interest in Pipe Line Holdings and $150 million in distributions to unitholders, general partner and noncontrolling interests, partially offset by $634 million in net long-term debt borrowings and $230 million in net proceeds from equity offerings.

Net cash used in financing activities decreased $62 million in 2014 compared to 2013, primarily due to $632 million in increased net long-term debt borrowings and $230 million in net proceeds from the equity offerings of common units representing limited partnership interests and contributions from MPLX GP LLC in exchange for a number of general

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partnership units that allowed it to maintain its two percent general partnership interest, partially offset by $810 million in increased distributions to MPC related to the acquisition of interests in Pipe Line Holdings.

Debt and Liquidity Overview

Our outstanding borrowings at December 31, 2015 and 2014 consisted of the following:

	December 31,	
(In millions)	2015	2014
MPLX LP:		
Bank revolving credit facility due 2020	$877	$385
Term loan facility due 2019	250	250
5.500% senior notes due 2023	710	—
4.500% senior notes due 2023	989	—
4.875% senior notes due 2024	1,149	—
4.000% senior notes due 2025	500	—
4.875% senior notes due 2025	1,189	—
Consolidated subsidiaries:		
MarkWest - 5.500% senior notes due 2023	40	—
MarkWest - 4.500% senior notes due 2023	11	—
MarkWest - 4.875% senior notes due 2024	1	—
MarkWest - 4.875% senior notes due 2025	11	—
MPL - capital lease obligations due 2020	9	10
Total	5,736	645
Unamortized debt issuance costs[1]	(8)	—
Unamortized discount[2]	(472)	—
Amounts due within one year	(1)	(1)
Total long-term debt due after one year	$5,255	$644

(1) We adopted the updated FASB debt issuance cost standard as of June 30, 2015. This has been applied retrospectively and there was no effect to the prior period presented.

(2) 2015 includes $465 million discount related to the difference between the fair value and the principal amount of the assumed MarkWest debt.

As described in further detail below, the increase in debt as of year-end 2015 compared to year-end 2014 was primarily related to debt assumed in the MarkWest Merger during 2015.

On November 20, 2014, MPLX entered into a credit agreement with a syndicate of lenders (“MPLX Credit Agreement”) which provides for a five-year, $1 billion bank revolving credit facility and a $250 million term loan facility. In connection with the closing of the MarkWest Merger, we entered into an amendment to our MPLX Credit Agreement to, among other things, increase the aggregate amount of revolving credit capacity under the credit agreement by $1 billion for total aggregate commitments of $2 billion and to extend the maturity of the revolving credit facility to December 4, 2020. The term loan facility was not amended and matures on November 20, 2019. Also in connection with the closing of the MarkWest Merger, MarkWest’s bank revolving credit facility was terminated and the approximately $943 million outstanding under MarkWest’s bank revolving credit facility was repaid with $850 million of borrowings under MPLX’s bank revolving credit facility and $93 million of cash. We incurred approximately $2 million of costs related to the borrowing on the bank revolving credit facility.

The bank revolving credit facility includes letter of credit issuing capacity of up to $250 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 from time-to-time during its term to a date that is one year after the then-effective maturity subject to the approval of lenders holding the majority of the commitments then outstanding, provided that the commitments of any non-consenting lenders will be terminated on the then-effective maturity date. During 2015, we borrowed $992 million under the bank revolving credit facility, at an average interest rate of 1.617 percent, and repaid $500 million of these borrowings. At December 31, 2015, we had $877 million of borrowings and $8 million in letters of credit outstanding under this facility, resulting in total unused loan availability of $1.1 billion, or 55.8 percent of the borrowing capacity.

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The term loan facility was drawn in full on November 20, 2014. The maturity date for the term loan facility may be extended for up to two additional one-year periods subject to the consent of the lenders holding a majority of the outstanding term loan borrowings, provided that the portion of the term loan borrowings held by any non-consenting lenders will continue to be due and payable on the then-effective maturity date. The borrowings under this facility during 2015 were at an average interest rate of 1.670 percent.

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 includes certain representations and warranties, affirmative and restrictive covenants and events of default that we consider to be usual and customary for an agreement of that type. 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 certain of our subsidiaries from incurring debt, creating liens on our assets and entering into transactions with affiliates. As of December 31, 2015, we were in compliance with this financial covenant with a ratio of Consolidated Total Debt to Consolidated EBITDA of 4.6 to 1.0, as well as other covenants contained in the Credit Agreement.

As of December 31, 2015, we had five series of senior notes outstanding: $750 million in aggregate principal amount on the senior notes issued in August 2012 and due February 2023; $1.0 billion aggregate principal amount on senior notes issued in January 2013 and due July 2023; $1.2 billion aggregate principal amount on senior notes issued in November 2014 and due in December 2024; $500 million aggregate principal amount on senior notes issued in February 2015 and due February 2025; and $1.2 billion aggregate principal amount on senior notes issued in June 2015 and due in June 2025 (altogether the “Senior Notes Outstanding”). As of December 31, 2015, there were no minimum principal payments on the Senior Notes Outstanding due during the next five years. For further discussion of the Senior Notes Outstanding and other debt related information, see Item 8. Financial Statements and Supplementary Data - Note 16.

Our intention is to maintain an investment grade credit profile. As of December 31, 2015, we had the following credit rating grade levels.

Rating Agency	Rating
Fitch	BBB- (stable outlook)
Moody’s	Baa3 (stable outlook)
Standard & Poor’s	BBB- (stable outlook)

The ratings 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 for our senior unsecured debt to below investment grade credit 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.

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Our liquidity totaled $1.7 billion at December 31, 2015 consisting of:

	December 31, 2015		
(In millions)	Total Capacity	Outstanding Borrowings	Available Capacity
MPLX - bank revolving credit facility(1)	$2,000	$(885)	$1,115
MPC Investment - loan agreement	500	$(8)	492
Total	$2,500	$(893)	1,607
Cash and cash equivalents			43
Total liquidity			$1,650

(1) Outstanding borrowings includes $8 million in letters of credit outstanding under this facility.

We expect our ongoing sources of liquidity to include cash generated from operations, borrowings under our revolving credit agreements, funding from MPC and opportunistically issuing additional debt and equity securities. 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, contractual obligations, repayment of debt maturities and quarterly cash distributions. MPC manages some of 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 other sources of liquidity, including formation of joint ventures or sales of non-strategic assets.

Equity Overview

The table below summarizes the changes in the number of units outstanding through December 31, 2015:

(In units)	Common	Class B	Subordinated	General Partner	Total
Balance at December 31, 2013	36,951,515	—	36,951,515	1,508,225	75,411,255
Unit-based compensation awards	15,479	—	—	316	15,795
Contribution of interest in Pipe Line Holdings	2,924,104	—	—	59,676	2,983,780
December 2014 equity offering	3,450,000	—	—	70,408	3,520,408
Balance at December 31, 2014	43,341,098	—	36,951,515	1,638,625	81,931,238
Unit-based compensation awards	18,932	—	—	386	19,318
Issuance of units for Pipe Line Holdings acquisition	—	—	—	—	—
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
Balance at December 31, 2015	296,687,176	7,981,756	—	6,800,475	311,469,407

For more details on equity activity, see Item 8. Financial Statements and Supplementary Data - Note 8.

We intend to pay a minimum quarterly distribution of $0.2625 per unit, which equates to $79.7 million per quarter, or $318.8 million per year, based on the number of common and general partner units. On January 25, 2016, we announced that the board of directors of our general partner had declared a distribution of $0.5000 per unit that was paid on February 12, 2016 to unitholders of record on February 4, 2016. This represents a 29 percent increase in 2015. 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.

The allocation of total quarterly cash distributions to general and limited partners is as follows for the year ended December 31, 2015, 2014 and 2013. 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.

(In millions)	2015	2014	2013
Distribution declared:			
Limited partner units - public	$151	$29	$23
Limited partner units - MPC	104	77	63
General partner units - MPC	6	2	2
Incentive distribution rights - MPC	54	4	—
Total distribution declared	$315	$112	$88
Cash distributions declared per limited partner common unit:			
Quarter ended March 31	$0.4100	$0.3275	$0.2725
Quarter ended June 30	0.4400	0.3425	0.2850
Quarter ended September 30	0.4700	0.3575	0.2975
Quarter ended December 31	0.5000	0.3825	0.3125
Year ended December 31	$1.8200	$1.4100	$1.1675

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, development or acquisition of additional pipeline 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:

(In millions)	2015	2014	2013
Maintenance	$31	$28	$22
Growth	259	65	88
Total capital expenditures	290	93	110
Less: Increase in capital accruals	25	12	(5)
Asset retirement expenditures	1	2	8
Additions to property, plant and equipment	264	79	107
Capital expenditures of unconsolidated subsidiaries(1)	24	—	—
Total gross capital expenditures	288	79	107
Joint venture partner contributions(2)	(8)	—	—
Total gross capital expenditures, net	$280	$79	$107

(1) Includes amounts related to unconsolidated, partnership operated subsidiaries.
(2) This represents estimated joint venture partners share of growth capital.

Our board originally approved a 2016 growth capital plan of $1.7 billion. In light of current market conditions, we expect capital spending to be between $800 million and $1.2 billion. The G&P segment capital plan is primarily for investment in gathering, processing, and fractionation infrastructure in the Marcellus and Utica shale plays, as well as the STACK and SCOOP formations in the Cana-Woodford Shale in Oklahoma and the Permian Basin in New Mexico and Texas. The L&S segment capital plan is primarily related to the Cornerstone project and downstream Utica infrastructure development. The Cornerstone project is the building block for the other projects that will become a critical solution for the industry to move condensate and natural gas liquids out of the Utica region into refining centers in Northwest Ohio and connect the pipelines to

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Canada. We continuously evaluate our capital plan and make changes as conditions warrant. On February 3, 2016, we announced that MPC has offered to contribute its inland marine business in exchange for securities, which would be in addition to the capital plan amounts above.

We have revised our timeline for completion of certain capital projects that are classified as construction in progress within Property, plant and equipment, net in the accompanying Consolidated Balance Sheets. The expected completion dates of these projects have been updated to more closely align with the timing by which we expect that they will be utilized by their respective producer customers as part of the just-in-time component of our capital program. We continue to believe all amounts capitalized will be recoverable as we expect these projects to be completed.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2015:

(In millions)	Total	2016	2017-2018	2019-2020	Later Years
Bank revolving credit facility(1)	$972	$19	$39	$914	$—
Term loan(1)	268	5	9	254	—
Long-term debt(1)	6,520	221	442	442	5,415
Capital lease obligations	11	1	3	7	—
Operating lease and long-term storage agreements(2)	303	49	89	65	100
Purchase obligations:					
Contracts to acquire property, plant & equipment	144	142	2	—	—
Other contracts	42	34	6	—	2
Total purchase obligations(3)	186	176	8	—	2
Natural gas purchase obligations(4)	91	12	25	26	28
SMR liability(5)	247	17	34	34	162
Transportation and terminalling(6)	619	68	134	118	299
Other long-term liabilities reflected on the Consolidated Balance Sheets:					
Other liabilities(7)	50	25	25	—	—
AROs(8)	17	—	—	—	17
Total contractual cash obligations	$9,284	$593	$808	$1,860	$6,023

(1) Amounts represent outstanding borrowings at December 31, 2015 plus any commitment and administrative fees and interest.

(2) Amounts relate primarily to a long-term propane storage agreement and our office 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 15 for the fair value of the frac spread sharing component). We use the estimated future frac spreads as of December 31, 2015 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.

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(5) Represents amounts due under a product supply agreement (see Item 8. Financial Statements and Supplementary Data -Note 22 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) Represents the payable for Class B units recorded in connection with the MarkWest Merger (see Item 8. Financial Statements and Supplementary Data - Note 4 for further discussion).

(8) Excludes estimated accretion expense of $20 million. The total amount to be paid is approximately $37 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 so long as MPC controls our general partner. Under the omnibus agreement, we pay to MPC in equal monthly installments an annual amount of approximately $37 million in 2015 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 $4 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 any out-of-pocket costs and expenses incurred by MPC on our behalf.

One of the employee services agreement with MPC addresses reimbursement to MPC for the provision of certain operational and management services to us in support of our pipelines, barge dock and tank farms. This employee services agreement has an initial term that extends through September 30, 2017. We pay MPC a monthly fee that reflects the total employee-based salary and wage costs (including accruals) incurred in providing these services during such month, including a monthly allocated portion of estimated employee benefit costs, bonus accrual, MPC stock-based compensation expense and employer payroll taxes, plus an additional $125,000. On December 28, 2015, MPLX LP entered into an employee services agreement with MW Logistics Services LLC (“MWLS”). Pursuant to the terms of the agreement, MWLS provides operational and management services to MPLX in support of the assets owned or operated by MarkWest, as well as certain other services to support the MPLX business. Under the terms of the agreement, MPLX pays MWLS a monthly fee to reflect the total employee-based salary, wage and benefits costs and other expenses incurred by MWLS in providing the services during such month. The agreement is effective until December 28, 2020 and automatically renews for two additional renewal terms for up to five years each unless terminated earlier under the provisions of the agreement. We incurred $97 million of expenses under the employee services agreements for 2015.

Off-Balance Sheet Arrangements

We do not engage in off-balance sheet financing activities. As of December 31, 2015, 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 prices of and demand for natural gas, NGLs, crude oil and refined products, actions of competitors, 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.

Effects of Inflation

Inflation did not have a material impact on our results of operations for the years ended December 31, 2015, 2014 or 2013. 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

MPC owns our general partner and an approximate 18.2 percent limited partner interest (excluding the Class A units owned by MarkWest Hydrocarbon, a wholly-owned subsidiary of the Partnership, and including the Class B units on an as-converted basis) in us as of February 12, 2016 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 72 percent, 86 percent and 83 percent of our total revenues and other income for 2015, 2014 and 2013. We provide to MPC crude oil and product pipeline transportation services based on regulated tariff rates and storage services based on contracted rates.

Of our total costs and expenses, MPC accounted for 31 percent for 2015 and 42 percent for 2014 and 2013. 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, other than certain transactions with MPC for periods prior to the Initial Offering, related to the provision of administrative services, have generally been conducted under terms comparable to those with unrelated parties. For further discussion of activity with related parties and MPC 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:

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(In millions)	2015		2014		2013	
Capital	$2		$2		$1	
Percent of total capital expenditures	1	%	3	%	—	%
Compliance:						
Operating and maintenance	$22		$22		$41	
Remediation[1]	2		2		5	
Total	$24		$24		$46	

(1) 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 $1 million in 2016. 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.

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.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Acquisitions In accounting for business combinations, acquired assets and liabilities, noncontrolling interests, if any, and 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. 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	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.	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. See Item 8. Financial Statements and Supplementary Data - Note 4 for additional information on the MarkWest Merger. That acquisition was completed effective December 4, 2015. Therefore, it is possible that adjustments will be made to the purchase price allocation during the year-ending December 31, 2016.

purchase gain, 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 interest, if any.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Long-Lived Assets		
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 a reporting unit 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 is the plant level for our G&P segment, the pipeline system level for our L&S segment, and the customer relationship for our customer contract intangibles.	Management considers the volume of reserves dedicated to be processed by the asset and future NGL product and natural gas 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 reserves 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 considered the sustained reduction of commodity prices in forecasted cash flows.	As of December 31, 2015, there were no indicators of impairment for any of our long-lived assets, primarily as a result of the G&P segment's assets and customer contract intangible assets being recorded at fair value as of December 4, 2015. A significant variance in any of the assumptions or factors used to estimate future cash flows would have resulted in a different allocation of the purchase price, resulting in an increased/(decreased) carrying value of goodwill recorded as of December 4, 2015. This would have changed depreciation/amortization expense on a prospective basis as long-lived assets are depreciated/amortized and goodwill is not amortized. See Item 8. Financial Statements and Supplementary Data - Note 4 for additional information on the MarkWest Merger.
Impairment of Goodwill		
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	Management performed a quantitative analysis and determined the fair value of our reporting units using the income and market approaches for our 2015 impairment analysis. These types of analyses require 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. Management also performed a quantitative analysis on	As of December 31, 2015, there were no indicators of impairment for our goodwill, primarily as a result of the goodwill allocated to reporting units in the G&P segment being recorded at their fair values in connection with the December 4, 2015 MarkWest Merger. The carrying values of the G&P segment reporting units equaled their fair values as of the date of the merger. Any decrease in the fair value of these reporting units going forward could result in an impairment charge to the approximate $2.5 billion of goodwill recorded in connection with the MarkWest Merger.

value is greater than the fair value.	the goodwill reported in the L&S segment. For the current year qualitative analysis, we analyzed whether there were any changes in the assumptions used to perform our December 4, 2015 purchase price allocation in light of current economic conditions to determine if it was more likely than not that impairment exists in the G&P segment. Management also performed a qualitative analysis on the goodwill reported in the L&S segment. 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 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.	In February of 2016, our units were trading at a price per unit significantly lower that the price per unit used to calculate the merger consideration and the resulting goodwill that was assigned to certain reporting units in our G&P segment. The significant assumptions that were used to develop the estimates of the fair values recorded in acquisition accounting and the resulting goodwill assigned to the reporting units included discount rates, growth rates and customer attrition rates. If we experience negative events related to these assumptions or if the market price of our units continues to trade at a low level in 2016, we may need to assess whether this is a change in circumstances that indicates it is more likely than not that the fair value of the reporting units to which the goodwill was assigned in connection with the merger is less than the carrying value and, if so, evaluate goodwill for impairment. See Item 8. Financial Statements and Supplementary Data - Note 4 for additional information on the MarkWest Merger.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Equity Investments		
We evaluate our equity method investments in Centrahoma, Jefferson Dry Gas, MarkWest Utica EMG and MarkWest Pioneer, for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of 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 an impairment should be recorded.	Our impairment assessment requires us to apply judgment in estimating future cash flows received from or attributable to our equity method investments. The primary estimates may include the expected volumes, the terms of related customer agreements and future commodity prices.	Our investments in Centrahoma, Jefferson Dry Gas, MarkWest Utica EMG and MarkWest Pioneer were recorded at fair value based on the MarkWest Merger on December 4, 2015. If expected cash flows used to determine the fair value as of December 4, 2015 are not realized our equity method investments may be subject to future impairment charges. See Item 8. Financial Statements and Supplementary Data - Note 4 for additional information on the MarkWest Merger.
Accounting for Risk Management Activities and Derivative Financial Instruments		
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.	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.	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% difference in our estimated fair value of Level 2 and 3 derivatives at December 31, 2015 would have affected income before income taxes by approximately $3 million for the year ended December 31, 2015.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Accounting for Significant Embedded Derivative Instruments Identifying and 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 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. 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.	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 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 fair value is also appropriately adjusted for non-performance risk each period. 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, 2015, we have estimated the probability that the producer customer will exercise its option to extend the agreements for the first renewal period is 50%, and for the second renewal period is 75% based on the inherent uncertainty of the variables that would impact its decision.	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 valuation model require specialized knowledge, as NGL price curves do not exist for the entire term of the arrangement. The valuation is sensitive to NGL and natural gas future price curves. Holding the natural gas curves constant, a 10% increase (decrease) in NGL price curves causes a 46% increase (decrease) in the liability as of December 31, 2015. Holding the NGL curves constant, a 10% increase (decrease) in the natural gas curves causes a 56% (decrease) increase in the liability as of December 31, 2015. 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% for the first renewal period and 50% for the second renewal period as of December 31, 2015, the liability would be reduced by 18%. If it were determined that the probability of exercise was 75% for the first renewal period and 100% for the second renewal period as of December 31, the liability would be increased by 21%. See Item 8. Financial Statements and Supplementary Data - Note 15 for more information related to the Natural Gas Embedded Derivative.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Variable Interest Entities		
We evaluate all legal entities in which we hold an ownership or other pecuniary interest to determine if the entity is a VIE. 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. 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. 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.	Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE. 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. 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. 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.	MarkWest Utica EMG and Ohio Condensate are VIEs; however, we are not considered to be the primary beneficiary. As a result, they are accounted for under the equity method. Changes in the design or nature of the activities of either of these entities, or our involvement with an entity, 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. Ohio Gathering is a subsidiary of MarkWest Utica EMG and is a VIE. If we were to consolidate MarkWest Utica EMG, Ohio Gathering would need to be assessed for consolidation or deconsolidation. We account for our ownership interest in Centrahoma and MarkWest Pioneer under the equity method and have determined that these entities are not VIEs. However, changes in the design or nature of the activities of either entities 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. See Item 8. Financial Statements and Supplementary Data - Note 5 for more

information on our other investments.

Income Taxes

Under the asset and liability method of income tax accounting, deferred tax assets and liabilities are determined based on differences between the financial reporting and the tax basis of assets and liabilities and are measured using the tax rates and laws that are expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

A deferred tax asset must be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized prior to expiration.

We have deferred tax assets related to NOL carryforwards. Management's assessment of our ability to utilize the NOL carryforwards depends upon our estimates of future taxable income. There are many risks and other factors that could cause our actual future taxable income to be significantly different than our estimates. These factors include but are not limited to, changes in production volumes of natural gas by our producer customers, our ability to retain customers, changes in laws or regulations impacting our operations, changes in commodity prices, etc.

As of December 31, 2015, we had tax-effected NOL carryforwards for federal and state income tax purposes of approximately $58 million and $4 million, respectively. We believe that we will be able to fully utilize these NOL carryforwards and therefore have not recorded a valuation allowance. If for any reason our future taxable income is less than we have estimated, we may not realize the full benefit of these NOL carryforwards.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Contingent Liabilities		
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.	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 interpretation, additional information on the extent and nature of site contamination and improvements in technology.	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. For additional information on contingent liabilities, see Item 8. Financial Statements and Supplementary Data - Note 22.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by 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

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price changes and, to a lesser extent, interest rate changes and non-performance by our customers and counterparties.

Commodity Price Risk

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of NGL transportation and fractionation capacity and a variety of additional factors that are beyond the Partnership’s control. Our profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at our own or third-party processing plants, purchasing and selling or gathering and transporting volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of natural gas drilling by our producer customers, such prices also affect profitability. To protect us financially against adverse price movements and to maintain more stable and predictable cash flows so that we can meet our cash distribution objectives, debt service and capital plans, we execute a strategy governed by our risk management policy. We have a committee comprised of senior management that oversees risk management activities, continually monitors the risk management program and adjusts our strategy as conditions warrant. We enter into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas, NGLs and crude oil. Derivative contracts utilized are swaps and options traded on the OTC market and fixed price forward contracts. The risk management policy does not allow us to take speculative positions with our derivative contracts.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have entered into derivative financial instruments relating to the future price of NGLs and crude oil. We currently manage the majority of our NGL price risk using direct product NGL derivative contracts. We enter into NGL derivative contracts when adequate market liquidity exists and future prices are satisfactory. A small portion of our NGL price exposure is managed by using crude oil contracts. Based on our current volume forecasts, we expect the majority of our derivative positions used to manage our future commodity price exposure will be direct product NGL derivative contracts.

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To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily utilize derivative financial instruments relating to the future price of natural gas and take into account the partial offset of our long and short natural gas positions resulting from normal operating activities. We have no such positions outstanding as of December 31, 2015.

As a result of our current derivative positions, we believe that we have mitigated a portion of our expected commodity price risk through the fourth quarter of 2016. 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, 2015, including the weighted-average prices (“WAVG”):

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2016	300	$63.56	$2,414

Ethane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016	16,800	$0.21	$244

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016	52,322	$0.52	$2,323

IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016 (Jan. - Mar.)	14,008	$0.72	$210

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016 (Jan. - Mar.)	4,213	$0.75	$77

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016 (Jan. - Mar.)	14,089	$1.22	$392

The following tables provides information on the volume of MarkWest Liberty Midstream’s commodity derivative activity positions related to long liquids price risk at December 31, 2015, including the WAVG:

Propane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016 (Jan. - Mar.)	78,346	$0.59	$1,437

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IsoButane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016 (Jan. - Mar.)	7,608	$0.71	$106

Normal Butane Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016 (Jan. - Mar.)	17,911	$0.67	$213

Natural Gasoline Swaps	Volumes (Gal/d)	WAVG Price (Per Gal)	Fair Value (in thousands)
2016	16,796	$1.22	$1,885

The following table provides information on the derivative positions related to long liquids price risk as of February 12, 2015 that we have entered into subsequent to December 31, 2015, including the WAVG:

Propane Swaps