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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2020

or

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

For the transition period from __________ to __________

Commission file number: 001-38260

BP Midstream Partners LP

(Exact name of registrant as specified in its charter)

Delaware	**82-1646447**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

501 Westlake Park Boulevard, Houston, Texas 77079
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: **(281) 366-2000**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Units, Representing Limited Partner Interests	BPMP	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐
Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the registrant's common units held by non-affiliates of the registrant as of June 30, 2020, was $548 million, based on the closing price of such units of $11.47 as reported on the New York Stock Exchange on such date. As of February 24, 2021, the registrant had 104,778,502 common units outstanding.

Documents Incorporated By Reference: None

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K (the “Annual Report”) includes various “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). All statements other than statements of historical fact included in this Annual Report, regarding the Partnership's strategy, future growth, future operations, future actions, the continued effects of the global coronavirus disease (“COVID-19”) pandemic on demand, the effects of the continued volatility of commodity prices and the related macroeconomic and political environment, volumes, capital requirements, conditions or events, future operating results or the ability to generate sales, our potential exposure to market risks, statements relating to the expected amount of cash available for distribution and level of distributions, financial position, estimated revenues and losses, projected cost, prospects, plans and objectives of management, are forward-looking statements.

When used in this Annual Report, you can identify our forward-looking statements by words such as “anticipate,” “believe,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “plan,” “predict,” “project,” “seek,” “target,” “could,” “may,” “should,” “would” or other similar expressions that convey the uncertainty of future events or outcomes, although not all forward-looking statements contain such identifying words. When considering forward-looking statements, you should carefully consider the risk factors and other cautionary statements described under the heading “Risk Factors” and other cautionary statements contained in this filing.

We based forward-looking statements on our current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. We caution you that these statements are not guarantees of future performance as they involved assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements.

Forward-looking statements may include statements about:

- The decline in global crude oil demand and crude oil prices for an uncertain period of time and the potential resulting significant reduction of domestic crude oil and natural gas production and significant declines in the actual or expected volumes transported through our pipelines and/or the reduction of commercial opportunities that might otherwise be available to us.
- Uncertainty regarding the easing of restrictions on various commercial and economic activities by applicable authorities, as well as the potential reinstatement of such restrictions, in response to the spread of COVID-19; such restrictions are designed to protect public health but also have the effect of significantly reducing demand for crude oil, natural gas, refined products and diluent.
- Uncertainty regarding the future actions of foreign oil producers such as Saudi Arabia and Russia and the risk that they take actions that will prolong or exacerbate the current over-supply of crude oil.
- Uncertainty regarding the timing, pace and extent of an economic recovery in the United States and elsewhere, which in turn will likely affect demand for crude oil and therefore the demand for the midstream services we provide and the commercial opportunities available to us.
- The impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations, including increased focus by the federal and state governments to develop renewable energy and climate-related policies.
- Our inability to perform our obligations under our contracts, whether due to non-performance by third parties, including our customers or counterparties, market constraints, third-party constraints, legal constraints (including governmental orders or guidance), or other factors.
- The continued ability of BP and any non-affiliate customers to satisfy their obligations under commercial and other agreements and the impact of lower market prices for crude oil, natural gas, refined products and diluent including the ability to satisfy such obligations as they may be impacted by the effects of COVID-19.
- The volume of crude oil, natural gas, refined products and diluent we transport or store and the prices that we can charge our customers.
- The tariff rates with respect to volumes that we transport through our regulated assets, which rates are subject to review and possible adjustment imposed by federal and state regulators.
- Changes in revenue that we realized under the fixed loss allowance provisions fees and tariffs resulting from changes in underlying commodity prices.
- Fluctuations in the prices for crude oil, natural gas, refined products and diluent.
- The level of onshore and offshore production and demand for crude oil, natural gas, refined products and diluent.
- Our ability to successfully integrate recently acquired assets and realize the anticipated benefits of such acquisitions.

- Changes in global economic conditions and the effects of a global economic downturn on the business of BP and the business of its suppliers, customers, business partners and credit lenders.
- Liabilities associated with the risks and operational hazards inherent in transporting and/or storing crude oil, natural gas, refined products and diluent.
- The impact of hurricanes and other severe weather disruptions to our offshore pipelines in the Gulf of Mexico.
- Curtailment of operations or expansion projects due to unexpected leaks or spills; severe weather disruption; riots, strikes, lockouts or other industrial disturbances; or failure of information technology systems due to various causes, including unauthorized access or attack.
- Costs or liabilities associated with federal, state and local laws and regulations relating to environmental protection and safety, including spills, releases and pipeline integrity.
- Costs associated with compliance with evolving environmental laws and regulations on climate change.
- Costs associated with compliance with safety regulations and system maintenance programs, including pipeline integrity management program testing and related repairs.
- Changes in tax status.
- Changes in the cost or availability of third-party vessels, pipelines, rail cars and other means of delivering and transporting crude oil, natural gas, refined products and diluent.
- Direct or indirect effects on our operations resulting from actual or threatened terrorist incidents or acts of war.
- Changes in, and availability to us of the equity and debt capital markets.

Many of the foregoing risks and uncertainties are, and will be, exacerbated by the COVID-19 pandemic and any consequent worsening of the global business and economic environment. New factors emerge from time to time, and it is not possible for us to predict all such factors. Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that the Partnership or persons acting on the Partnership's behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

GLOSSARY OF TERMS

As used in this Annual Report, the identified terms have the following meanings:

Barrel	*One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.*
Bbl	*Barrel.*
BSEE	*Bureau of Safety and Environmental Enforcement.*
BP	*BP p.l.c. and, unless context otherwise requires, its controlled affiliates, other than BP Midstream Partners LP, its subsidiaries and general partner.*
BP2	*BP#2 crude oil pipeline system and related assets.*
BP2 OpCo	*BP Two Pipeline Company LLC, which owns BP2.*
BPA	*BP America Inc.*
BP Holdco	*BP Midstream Partners Holdings LLC.*
BPMP	*BP Midstream Partners LP listed on the New York Stock Exchange.*
BP Pipelines	*BP Pipelines (North America), Inc.*
BP Products	*BP Products North America, Inc.*
Capacity	*A pipeline's individual or aggregate capacity is intended as the capacity for the primary purpose of the pipeline based on our experience and/or calculations. For crude pipeline systems, this is typically the delivery capacity to the final destination (even if the system has segments with differing capacity). For product pipeline systems, this is typically the capacity to transport to one or where appropriate a number of delivery points along the pipeline. Furthermore, note that the capacity of a pipeline can change based on the mix of commodities shipped, the physical characteristics of those commodities, the destination of the commodity, and the operating scenario. Therefore, the capacity stated is subject to change based on future physical modifications, commodity changes, or changes in operating scenarios.*

CERCLA	*Comprehensive Environmental Response, Compensation, and Liability Act.*
Clean Water Act	*Water Pollution Control Act of 1972.*
Common carrier pipeline	*A pipeline engaged in the transportation of crude oil, refined products or natural gas liquids as a common carrier for hire.*
Crude oil	*A mixture of raw hydrocarbons that exists in liquid phase in underground reservoirs.*
Delaware Act	*Delaware Revised Uniform Limited Partnership Act.*
Diamondback	*Diamondback diluent pipeline system and related assets.*
Diamondback OpCo	*BP D-B Pipeline Company LLC, which owns Diamondback.*
Diluent	*A light hydrocarbon mixture which, when blended with heavy crude petroleum, reduces the viscosity of crude to make it more efficient to transport by pipeline.*
DOI	*Department of Interior.*
DOT	*Department of Transportation.*
DRA	*Drag reducing agent.*
EPA	*Environmental Protection Agency.*
EPAct	*Energy Policy Act of 1992.*
Estimated Total Maintenance Spend	*Estimated Total Maintenance Spend is a defined term under our partnership agreement. It is estimated annually (and whenever an event occurs that is likely to result in a material adjustment) by the board of directors of our general partner. It is intended to represent the average quarterly Maintenance Capital Expenditures (as such term is defined below) and maintenance expenses that the Partnership will need to incur over the long term to maintain the operating capacity or operating income of the Partnership and its subsidiaries (including the Partnership's proportionate share of the average quarterly Maintenance Capital Expenditures and maintenance expenses of its subsidiaries that are not wholly owned) existing at the time the estimate is made.*
Expansion capital expenditures	*Expansion capital expenditures is a defined term under our partnership agreement. Expansion capital expenditures are cash expenditures (including transaction expenses) for capital improvements. Expansion capital expenditures do not include maintenance capital expenditures or investment capital expenditures. Expansion capital expenditures do include interest payments (including periodic net payments under related interest rate swap agreements) and related fees paid during the construction period on construction debt. Where cash expenditures are made in part for expansion capital expenditures and in part for other purposes, the general partner determines the allocation between the amounts paid for each.*
FASB	*Financial Accounting Standards Board.*
FERC	*Federal Energy Regulatory Commission.*
Fixed loss allowance or FLA	*An allowance for volume losses due to measurement difference set forth in crude oil product transportation agreements, including long-term transportation agreements and tariffs for crude oil shipments.*
GAAP	*United States generally accepted accounting principles.*
Gal	*Gallons.*
GHG	*Greenhouse gas.*
HCA	*High Consequence Area.*
ICA	*Interstate Commerce Act.*
Investment capital expenditures	*Investment capital expenditures means capital expenditures other than Maintenance capital expenditures and Expansion capital expenditures.*
IPO	*Initial Public Offering of BP Midstream Partners LP.*
IPO Contributed Assets	*100% interest in each BP2 OpCo, River Rouge OpCo and Diamondback OpCo, a 28.5% interest in Mars and a 20% managing interest in Mardi Gras.*
IRS	*Internal Revenue Service.*
kboe	*One thousand barrels of oil equivalent.*
kbpd	*Thousand barrels per day.*
LIBOR	*London Interbank Offered Rate.*
LTIP	*BP Midstream Partners LP 2017 Long-Term Incentive Plan.*

Maintenance capital expenditures	*Maintenance capital expenditures is a defined term under our partnership agreement. Maintenance capital expenditures are cash expenditures (including expenditures for (a) the acquisition (through an asset acquisition, merger, stock acquisition, equity acquisition or other form of investment) by the Partnership or any of its subsidiaries of existing assets or assets under construction, (b) the construction or development of new capital assets by the Partnership or any of its subsidiaries, (c) the replacement, improvement or expansion of existing capital assets by the Partnership or any of its subsidiaries or (d) a capital contribution by the Partnership or any of its subsidiaries to a person that is not a subsidiary in which the Partnership or any of its subsidiaries has, or after such capital contribution will have, directly or indirectly, an equity interest, to fund the Partnership or such subsidiary's share of the cost of the acquisition, construction or development of new, or the replacement, improvement or expansion of existing, capital assets by such person), in each case if and to the extent such acquisition, construction, development, replacement, improvement or expansion is made to maintain, over the long-term, the operating capacity or operating income of the Partnership and its subsidiaries, in the case of clauses (a), (b) and (c), or such person, in the case of clause (d), as the operating capacity or operating income of the Partnership and its subsidiaries or such person, as the case may be, existed immediately prior to such acquisition, construction, development, replacement, improvement, expansion or capital contribution. For purposes of this definition, "long-term" generally refers to a period of not less than twelve months. Maintenance capital expenditures do not include expansion capital expenditures or investment capital expenditures.*
MLP	*Master limited partnership.*
MMscf	*One million standard cubic feet.*
MMscf/d	*One million standard cubic feet per day.*
MVC	*Minimum Volume Commitment.*
NEPA	*National Environmental Policy Act.*
NGA	*Natural Gas Act.*
NYSE	*New York Stock Exchange.*
OCSLA	*Outer Continental Shelf Lands Act.*
OPA-90	*Oil Pollution Act of 1990.*
OSHA	*Occupational Safety and Health Act.*
PHMSA	*Pipeline and Hazardous Materials Safety Administration.*
PPI	*U.S. Producer Price Index.*
Predecessor	*The historical financial results of BP2, River Rouge, and Diamondback.*
RCRA	*Resource Conservation and Recovery Act.*
River Rouge	*Whiting to River Rouge refined products pipeline system and related assets.*
River Rouge OpCo	*BP River Rouge Pipeline Company LLC, which owns River Rouge.*
Refined products	*Hydrocarbon compounds, such as gasoline, diesel fuel, jet fuel and residual fuel, that are produced by a refinery.*
ROFO	*Right of First Offer.*
SEC	*Securities and Exchange Commission.*
Throughput	*The volume of crude oil, refined products, diluent or natural gas transported or passing through a refinery, pipeline, terminal or other facility during a particular period.*
Total Maintenance Spend	*The sum of (a) the maintenance expenses of the IPO: Contributed Assets, (b) the maintenance capital expenditures of the IPO Contributed Assets, excluding any reimbursable maintenance capital expenditures, and (c) our allocable portion of the sum of (1) the maintenance expenses of Mars, Ursa, KM Phoenix and each of the Mardi Gras Joint Ventures and (2) the maintenance capital expenditures of Mars, Ursa, KM Phoenix and each of the Mardi Gras Joint Ventures, excluding any reimbursable maintenance capital expenditures.*
Wholly Owned Assets	*100% interest in each of BP2 OpCo, River Rouge OpCo and Diamondback OpCo.*
WTI	*West Texas Intermediate.*

BP MIDSTREAM PARTNERS LP

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PART I

Unless otherwise stated or the context otherwise indicates, all references to "we," "our," "us," or similar expressions refer to the legal entity BP Midstream Partners LP (the "Partnership"). The term "our Parent" refers to BP Pipelines (North America), Inc. ("BP Pipelines"), any entity that wholly owns BP Pipelines, indirectly or directly, including BP America Inc. and BP p.l.c. ("BP"), and any entity that is wholly owned by the aforementioned entities, excluding BP Midstream Partners LP.

Item 1 and 2. BUSINESS AND PROPERTIES

Overview

BP Midstream Partners LP is a Delaware limited partnership formed on May 22, 2017 by BP Pipelines, an indirect wholly owned subsidiary of BP, a "foreign private issuer" within the meaning of the Securities Exchange Act of 1934, as amended. On October 30, 2017, the Partnership completed its initial public offering (the "IPO") of common units representing limited partner interests.

We are a fee-based, growth-oriented master limited partnership formed to own, operate, develop and acquire pipelines and other midstream assets. Partnership assets consist of interests in entities that own crude oil, natural gas, refined products and diluent pipelines and refined product terminals serving as key infrastructure for BP and other customers to transport onshore crude oil production to BP's Whiting Refinery and offshore crude oil and natural gas production to key refining markets and trading and distribution hubs. Certain Partnership assets deliver refined products and diluent from the Whiting Refinery and other U.S. supply hubs to major demand centers.

Businesses and Assets

As of December 31, 2020, the Partnership's assets consisted of the following:

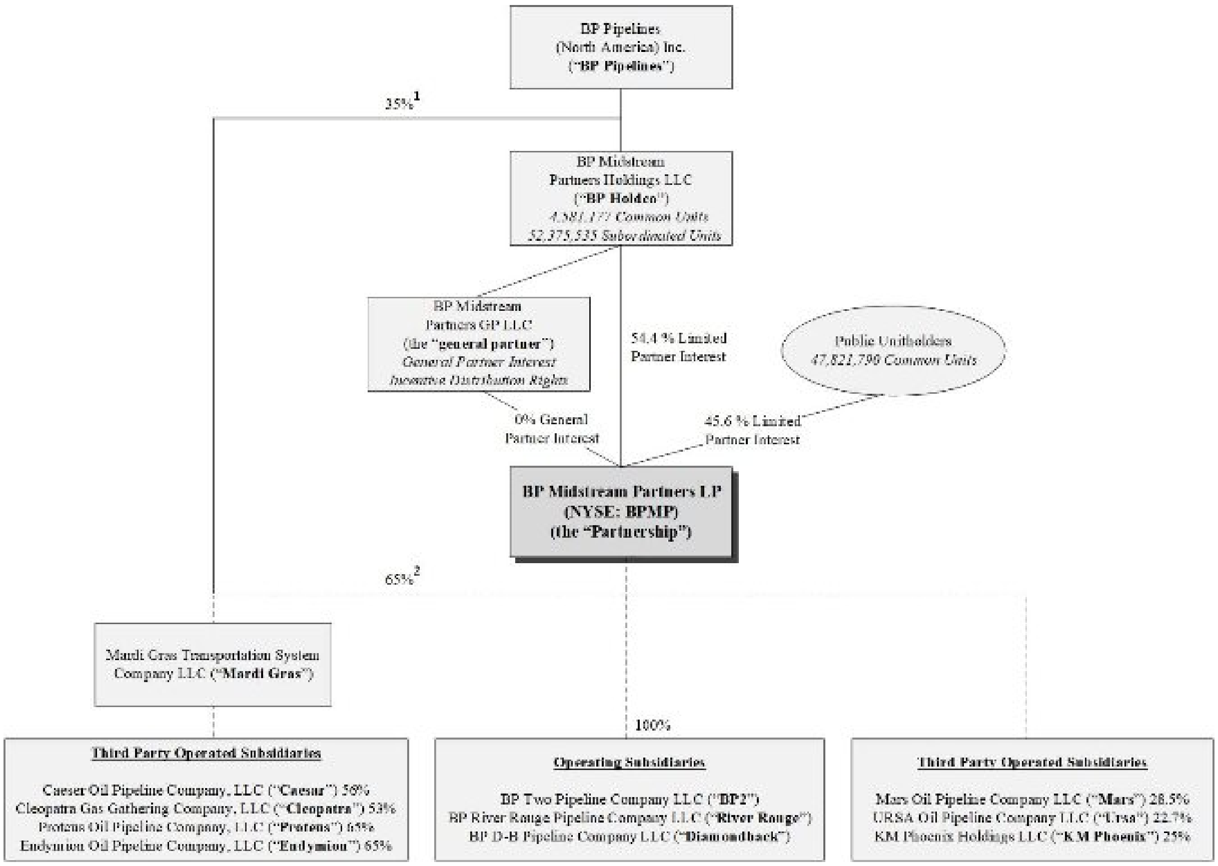
- BP Two Pipeline Company LLC, which owns the BP#2 crude oil pipeline system ("BP2").
- BP River Rouge Pipeline Company LLC, which owns the Whiting to River Rouge refined products pipeline system ("River Rouge").
- BP D-B Pipeline Company LLC, which owns the Diamondback diluent pipeline system ("Diamondback"). BP2, River Rouge, and Diamondback together are referred to as the "Wholly Owned Assets".
- 28.5% ownership interest in Mars Oil Pipeline Company, LLC ("Mars"), which owns a major corridor crude oil pipeline system in the Gulf of Mexico.
- 65% ownership interest and 100% managing member interest in Mardi Gras Transportation System Company, LLC ("Mardi Gras"), which holds the following investments in joint ventures located in the Gulf of Mexico:
    - 56% ownership interest in Caesar Oil Pipeline Company, LLC ("Caesar"),
    - 53% ownership interest in Cleopatra Gas Gathering Company, LLC ("Cleopatra"),
    - 65% ownership interest in Proteus Oil Pipeline Company, LLC ("Proteus"), and,
    - 65% ownership interest in Endymion Oil Pipeline Company, LLC ("Endymion"). Together Endymion, Caesar, Cleopatra and Proteus are referred to as the "Mardi Gras Joint Ventures."
- 22.7% ownership interest in Ursa Oil Pipeline Company, LLC ("Ursa").
- 25% ownership interest in KM Phoenix Holdings, LLC ("KM Phoenix").

The Partnership generates a majority of revenue by charging fees for the transportation of crude oil, refined products and diluent through pipelines under long-term agreements with minimum volume commitments ("MVC"). We do not engage in the marketing and trading of any commodities. All operations are conducted in the United States, and all long-lived assets are located in the United States. Partnership operations consist of one reportable segment.

Certain Partnership businesses are subject to regulation by various authorities including, but not limited to, the Federal Energy Regulatory Commission ("FERC"). Regulatory bodies exercise statutory authority over matters such as common carrier tariffs, construction, rates and ratemaking and agreements with customers.

Organizational Structure

The following simplified diagram depicts our organizational structure as of December 31, 2020. As discussed in Note 17 - *Subsequent Events* in the Notes to Consolidated Financial Statements, on February 12, 2021, all of our subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated.



(1) The remainder of Mardi Gras is held 34% by BP Pipelines and 1% by an affiliate of BP.
(2) The Partnership's interest in Mardi Gras is a managing member interest that provides us with the right to vote Mardi Gras' ownership interest in the Mardi Gras Joint Ventures.

Our Assets and Operations

The table below sets forth certain information regarding our assets as of December 31, 2020:

Entity/Asset	Product Type	Our Ownership Interest		BP Pipelines Retained Ownership Interest	Pipeline Length (Miles)	Capacity (kbpd)(1)		Contract Structure	
BP2	Crude	100.0 %		—	12	475		MVCs/FERC tariff Long term contract	(3)
River Rouge	Refined Products	100.0 %		—	244	80		MVCs/FERC tariff Long term contract	(3)
Diamondback	Diluent	100.0 %		—	42	135		MVCs/FERC tariff/ Long term contract	(3)
Mars	Crude	28.5 %		—	163	400	(2)	FERC and state tariffs/Lease dedication; Portion with guaranteed return	
Mardi Gras(4):		65.0 %	(5)	35.0 %					
Caesar	Crude	36.4 %		19.6 %	115	450		Lease dedication	
Cleopatra	Natural Gas	34.5 %		18.5 %	115	500		Lease dedication	
Proteus	Crude	42.3 %		22.7 %	70	425		Lease dedication	
Endymion	Crude	42.3 %		22.7 %	90	425		Lease dedication	
Ursa	Crude	22.7 %		—	47	150		Joint tariff	
KM Phoenix	Storage	25.0 %		—				Commercial agreements	

(1) The approximate capacity information presented is in kbpd with the exception of the approximate capacity related to Cleopatra gas gathering system, which are presented in MMscf/d. Pipeline capacities are based on current operations and vary depending on the specific products being transported and delivery point, among other factors.

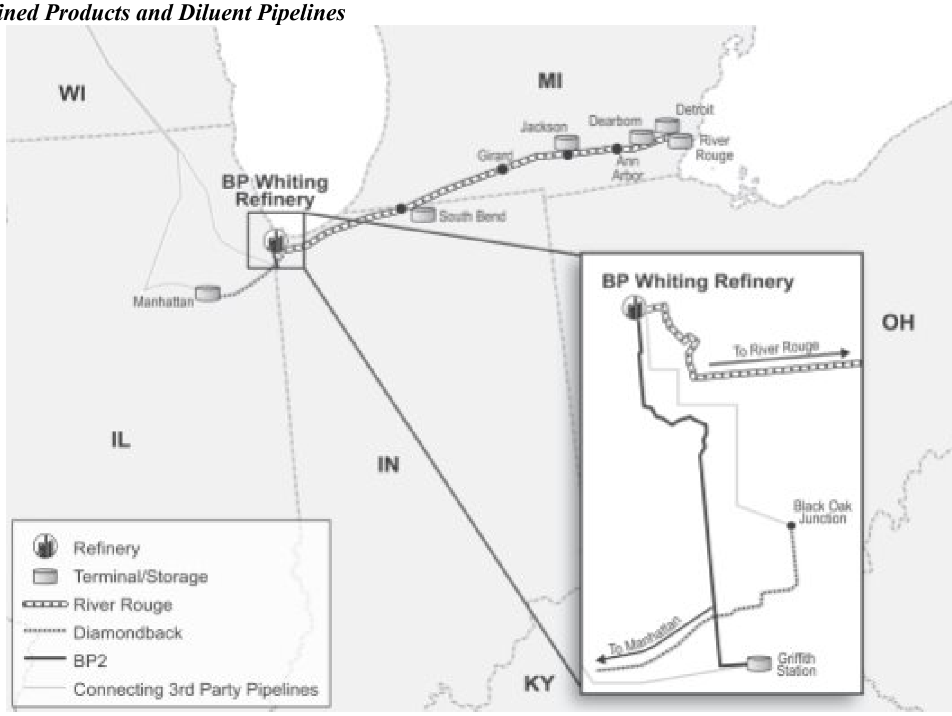
(2) Represents Mars capacity of the approximately 54 mile segment from the connections to Ursa, Medusa and Olympus pipelines at the West Delta 143 platform complex to Fourchon, Louisiana where Mars has a connection with Amberjack pipeline for ultimate delivery to Clovelly, Louisiana. The capacity of the Mars pipeline system ranges from 100 kbpd to 600 kbpd depending on the pipeline segment and the type of crude oil transported.

(3) BP has historically been the sole shipper on BP2 and River Rouge. Substantially all of our revenue on BP2, Diamondback and River Rouge is supported by commercial agreements with BP Products.

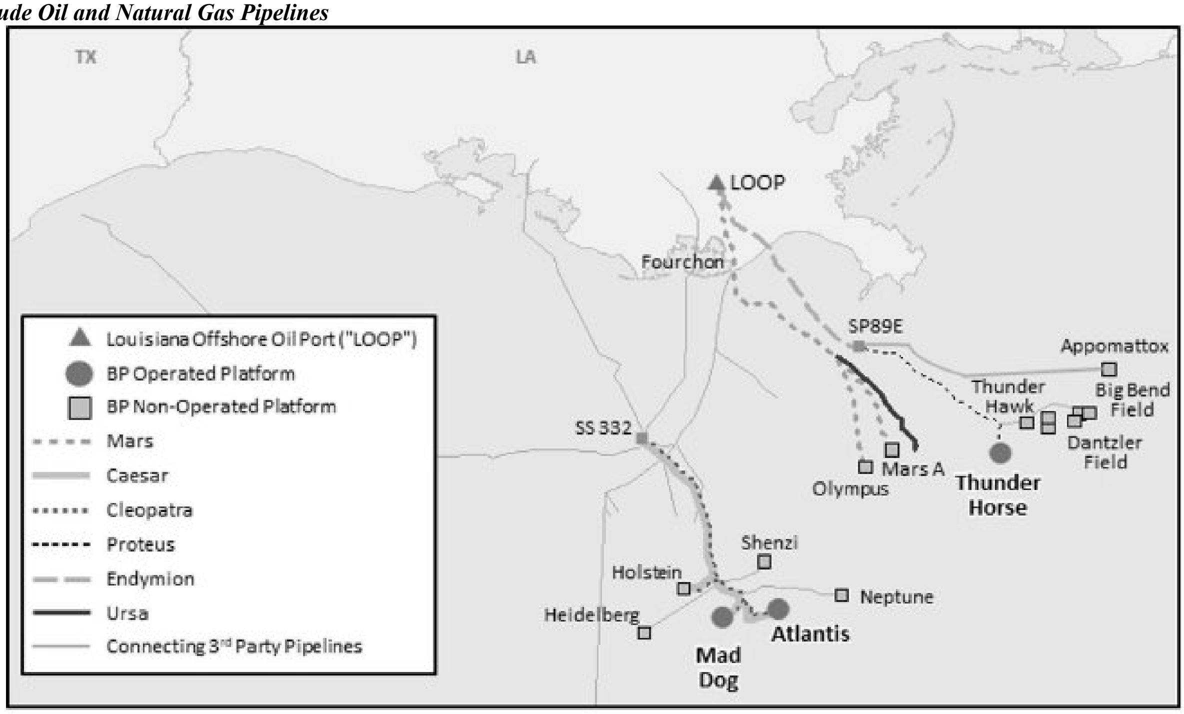
(4) Our ownership interest and BP Pipelines' and its affiliates' retained ownership interest in each of Caesar, Cleopatra, Proteus and Endymion represents 65% and 35%, respectively, of the 56%, 53%, 65% and 65% ownership interests in such Mardi Gras Joint Ventures, respectively, held by Mardi Gras.

(5) Our 65% interest in Mardi Gras includes a managing member interest that provides us with the right to vote Mardi Gras' retained ownership interest in the Mardi Gras Joint Ventures.

Onshore Crude Oil, Refined Products and Diluent Pipelines



Offshore Crude Oil and Natural Gas Pipelines



Our Commercial Agreements with BP

Minimum Volume Commitment Agreements

Our onshore assets provide vital movements to and from, and are integral to the operation of, BP's Whiting Refinery. We have commercial agreements with BP Products for our onshore pipelines that include minimum volume commitments and support substantially all of our aggregate revenue on BP2, River Rouge and Diamondback. Under these fee-based agreements, we provide transportation services to BP Products, and BP Products has committed to pay us for minimum volumes of crude oil, refined products and diluent, regardless of whether such volumes are physically shipped by BP Products through our pipelines during the term of the agreements.

Pipeline	Period*	Annual Minimum Throughput Commitment (kbpd)**
BP2	2020	320
	2021	300
	2022	290
	2023	280
River Rouge	Q4 2017 - 2020	60
	2021 - 2023	60
Diamondback	Q3 2017 - Q2 2022	23
	Q4 2017 - 2020	20
	2021 - 2023	10

* On November 3, 2020, the Partnership entered into throughput and deficiency agreements with BP Products with respect to volumes transported on BP2, River Rouge and Diamondback. These new agreements have a term of three years beginning January 1, 2021 and expiring December 31, 2023. The Partnership had existing agreements on the same pipelines with BP Products that expired on December 31, 2020.

** Transportation fee rate is the posted tariff.

Under each of our throughput and deficiency, or "minimum volume commitment," agreements, BP Products is obligated to throughput certain minimum volumes of crude oil, refined products and diluent on our onshore pipelines and pay the applicable tariff rates with respect to such volumes.

The following sets forth additional information regarding each of our minimum volume commitment agreements:

BP2 Throughput and Deficiency Agreement. Under this agreement, if BP Products fails to transport its minimum throughput volume on our BP2 pipeline from Griffith, Indiana to the Whiting Refinery during any month through December 31, 2023, then BP Products will pay us a deficiency payment equal to the volume of the deficiency multiplied by the contractual rate, which is calculated based on the applicable tariff rate then in effect (the "Deficiency Payment"). The amount of any deficiency payment paid by BP Products under this agreement may be applied as a credit for any volumes transported on our BP2 pipeline in excess of BP Products' minimum volume commitment during the calendar year in which such credits arose, after which time any unused credits will expire.

River Rouge Throughput and Deficiency Agreement. Under this agreement, if BP Products fails to transport its minimum throughput volume on River Rouge from Whiting, Indiana to various terminals along the pipeline during any month through December 31, 2023, then BP Products will pay us a Deficiency Payment. The amount of any deficiency payment paid by BP Products under this agreement may be applied as a credit for any volumes transported on River Rouge in excess of BP Products' minimum volume commitment during the calendar year in which such credits arose, after which time any unused credits will expire.

Diamondback Throughput and Deficiency Agreements. Under this agreement, if BP Products fails to transport its minimum throughput volume on our Diamondback pipeline from Gary, Indiana to Manhattan, Illinois during any month through December 31, 2023, then BP Products will pay us, during such period, a deficiency payment. The amount of any Deficiency Payment paid by BP Products under this agreement may be applied as a credit for any volumes transported on our Diamondback pipeline in excess of BP Products' minimum volume commitment during the calendar year in which such credits arose, after which time any unused credits will expire.

In addition, we are a party to one throughput and deficiency agreement with BP Products and one dedication agreement with a third party for Diamondback. The dedication agreement with a third party on Diamondback automatically renewed in 2021 and will now expire in June 2022. This contract is subject to successive one-year renewal periods at the election of the parties. The throughput and deficiency agreement for Diamondback automatically renewed in 2021 and will now expire in June 2022.

Termination of Throughput and Deficiency Agreements. BP Products has the right to terminate these agreements if we fail to perform any of our material obligations and fail to correct such non-performance within specified periods, or in the event of a change of control of our general partner.

BP Products is not permitted to suspend or reduce its obligations under these agreements in connection with the shutdown of the Whiting Refinery for any reason other than certain force majeure events, including for scheduled maintenance or other regular servicing or maintenance.

Under these agreements, if a force majeure event occurs and renders us or BP Products unable to meet our respective obligations under the agreement and continues for 365 consecutive days or more, then the party not claiming non-performance due to such force majeure event shall have the right to terminate the agreement on no less than 30 days' prior written notice to the other party.

Right of First Offer

We have entered into an omnibus agreement with BP Pipelines under which BP Pipelines granted us a ROFO, for a period ending on the earlier of (i) seven years after the IPO or (ii) the date on which BP Pipelines or its affiliates cease to control our general partner. Pursuant to the ROFO, BP Pipelines has agreed and will cause its affiliates to agree that if BP Pipelines or any of its affiliates decide to attempt to sell (other than to another affiliate of BP Pipelines) BP Pipelines' retained ownership interest in Mardi Gras and all of BP Pipelines' interests in midstream pipeline systems and assets related thereto in the contiguous United States and offshore Gulf of Mexico that were owned by BP Pipelines at the closing of the IPO (the "Subject Assets"), BP Pipelines or its affiliate will notify us of its desire to sell such Subject Assets and, prior to selling such Subject Assets to a third party, will allow us 45 days from such notice to make a binding written offer regarding such Subject Assets. In addition to BP Pipelines' retained ownership interest in Mardi Gras, the assets subject to our ROFO include three crude oil and natural gas liquid pipeline systems with an aggregate gross length of approximately 1,550 miles and an aggregate gross capacity of approximately 1,800 kbpd and nine refined products pipeline systems with an aggregate gross length of approximately 1,940 miles and an aggregate gross capacity of approximately 620 kbpd, as of December 31, 2020.

The consideration to be paid by us for the Subject Assets, as well as the consummation and timing of any acquisition by us of those assets, would depend upon, among other things, the timing of BP Pipelines' decision to sell those assets and our ability to successfully negotiate a price and other mutually agreeable purchase terms for those assets. Refer to *Part I, Item 1A. Risk Factors—Risks Related to Our Business*—If we are unable to make acquisitions on economically acceptable terms from BP or third parties, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders.

Payment of Administrative Fee and Reimbursement of Expenses

Under the omnibus agreement, we initially agreed to pay BP Pipelines an administrative fee of $13.3 million annually (payable in equal monthly installments), to reimburse BP Pipelines and its affiliates for the provision of certain general and administrative services for our benefit, including services related to the following areas: executive management services; financial management and administrative services (such as treasury and accounting); information technology services; legal services; health, safety and environmental services; land and real property management services; human resources services; procurement services; corporate engineering services; business development services; investor relations, communications and external affairs; insurance administration and tax related services.

Under this agreement, we initially agreed to also reimburse BP Pipelines and its affiliates for all other direct or allocated costs and expenses incurred by BP Pipelines in providing these services to us, including personnel costs related to the direct operation, management, maintenance and repair of the assets. This reimbursement is in addition to our reimbursement of our general partner and its affiliates for certain costs and expenses incurred on our behalf for managing and controlling our business and operations as required by our partnership agreement.

The fee was adjusted to $13.6 million per year, payable in equal monthly installments, beginning on January 1, 2019, and adjusted to $15.2 million per year, payable in equal monthly installments, beginning on January 1, 2020. During the second quarter of 2020, our Parent agreed to adjust the fee payable under the Omnibus Agreement back to the 2019 annual fee, beginning in the second quarter, prorated for the remainder of 2020 due to the ongoing economic effects of the global

COVID-19 pandemic. This resulted in a 2020 annual fee of $14.0 million. The annual fee was adjusted to $15.5 million per year, payable in equal monthly installments, beginning on January 1, 2021.

Our general partner, in good faith, may adjust the administrative fee to reflect, among others, any change in the level or complexity of our operations, a change in the scope or cost of services provided to us, inflation or a change in law or other regulatory requirements, the contribution, acquisition or disposition of our assets or any material change in our operation activities.

Customers

BP is our primary customer. Total revenue from BP represented 97.8%, 97.7%, and 97.6% of our revenues in the years ended December 31, 2020, 2019 and 2018, respectively. BP's volumes represented approximately 95.2%, 95.1% and 94.9% of the aggregate total volumes transported on the Wholly Owned Assets for the years ended December 31, 2020, 2019 and 2018, respectively.

In addition, we transport crude oil, natural gas and diluent for a mix of third-party customers, including crude oil producers, refiners, marketers and traders, and Partnership assets are connected to other crude oil, natural gas and diluent pipeline systems. In addition to serving directly connected Midwestern U.S. and Gulf Coast markets, our pipelines have access to customers in various regions of the United States and Canada through interconnections with other major pipelines. Our customers use our transportation services for a variety of reasons. Producers of crude oil require the ability to deliver their product to market and frequently enter into firm transportation contracts to ensure that they will have sufficient capacity available to deliver their product to delivery points with greatest market liquidity. Marketers and traders generate income from buying and selling crude oil, natural gas, refined products and diluent to capitalize on price differentials over time or between markets. Our customer mix can vary over time and largely depends on the crude oil, natural gas, refined products and diluent supply and demand dynamics in our markets.

Competition

Our pipelines face competition from a variety of alternative transportation methods including rail, water borne movements including barging and shipping, trucking and other pipelines that service the same markets as our pipelines. Our terminals compete for throughput and storage opportunities in the geographic areas in which they operate.

Competition for refined products in the Midwest is affected by supply and demand. Supply is driven by the volume of products produced by refineries in that area, the availability of products to get transported to the area and the cost of transportation to that area from other geographies. As a result of our affiliate relationships and the scope and scale of our refined products pipeline system, we believe that our refined product pipeline will not face significant new competition in the near-term.

Even though our offshore lines are supported by fee-based life-of-lease transportation agreements, our offshore pipelines compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. The principal competition for our offshore pipelines includes other crude oil and natural gas pipeline systems as well as producers who may elect to build or utilize their own transportation assets, although the barrier to new entrants is high due to the cost and environmental permitting required. In addition, the ability of our offshore pipelines to access future reserves will be subject to our ability, or the producers' ability, to fund the significant capital expenditures required to connect to the new production. In general, except for Mars, our offshore pipelines are not currently subject to regulatory rate-making authority, and the rates our offshore pipelines charges for services are dependent on market and economic conditions.

We also face increased indirect competition from alternative energy sources, such as wind or solar power, and these alternative energy sources could become even more competitive as various states and the federal government develop renewable energy and climate related policies, including taking actions to restrict the production of oil and gas.

FERC and Common Carrier Regulations

Our common carrier pipeline systems are subject to regulation by various federal, state and local agencies.

FERC regulates interstate transportation on our common carrier refined products, diluent, and crude oil pipeline systems under the ICA as modified by the Elkins Act, the EPAct and the rules and regulations promulgated under those laws. FERC regulations require that rates and terms and conditions of service for interstate service pipelines that transport crude oil, refined products and diluent (collectively referred to as “petroleum pipelines”) and certain other liquids, be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC’s regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Under the ICA, FERC or interested persons may challenge either existing or proposed new or changed rates, services, or terms and conditions of service. FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. Under certain circumstances, FERC could limit a common carrier pipeline’s ability to charge rates until completion of an investigation during which FERC could find that the new or changed rate is unlawful. In contrast, FERC has clarified that initial rates and terms of service agreed upon with committed shippers in a transportation services agreement are not subject to protest or a cost-of-service analysis where the pipeline held an open season offering all potential shippers service on the same terms.

A successful rate challenge could result in a common carrier pipeline paying refunds of revenue collected in excess of the just and reasonable rate, together with interest for the period, if any, that the rate was in effect. FERC may also order a pipeline to reduce its rates prospectively and may require a common carrier pipeline to pay shippers reparations retroactively for rate overages for a period of up to two years prior to the date the complaint was filed. FERC also has the authority to require changes to a pipeline's terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential. We may at any time also be required to respond to governmental requests for information, including compliance audits conducted by FERC.

The EPAct required FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer’s Price Index for Finished Goods (“PPI-FG”). The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC’s indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2021 and ending June 30, 2026, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG plus 0.78%. However, requests for rehearing of the December 2020 order establishing this indexing amount were filed with FERC and those requests remain pending, with rehearing granted for purposes of extending the time FERC has to review the requests. We cannot predict whether or to what extent the index factor may change in the future. A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so. Rate increases made under the index are presumed to be just and reasonable and require a protesting party to 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. Despite these procedural limits on challenging the indexing of rates, the overall rates are not entitled to any specific protection against rate challenges. 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. Many existing pipelines, including BP2, River Rouge, Diamondback, and Mars, utilize the FERC oil index to change transportation rates annually every July 1.

While common carrier pipelines often use the indexing methodology to change their rates, common carrier pipelines may elect to support proposed rates by using other methodologies such as cost-of-service ratemaking, market-based rates, and settlement rates. A common carrier pipeline can propose a cost-of-service approach when seeking to increase its rates above the rate ceiling (or when seeking to avoid lowering rates to the reduced rate ceiling), but must establish that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. A common carrier can charge market-based rates if it establishes that it lacks significant market power in the affected markets. A common carrier can change existing rates under settlement if agreed upon by all current shippers. Initial rates for a new service on a common carrier pipeline can be established through a negotiated rate with an unaffiliated shipper, but if challenged must be supported by a cost of service.

Intrastate services provided by certain of our pipeline systems are subject to regulation by state regulatory authorities, such as the Louisiana Public Service Commission, which currently regulates Mars. State agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates and proposed rate increases. State agencies may also investigate rates, services, and terms and conditions of service on their own initiative. State regulatory commissions could limit our ability to increase our rates or to set rates based on our costs or order us to reduce our rates and require the payment of refunds to shippers.

If our rate levels were investigated by FERC or a state commission, the inquiry could result in 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;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

FERC or a state commission could order us to change our rates, services, or terms and conditions of service or require us to pay shippers reparations, together with interest and subject to the applicable statute of limitations, if it were determined that an established rate, service, or terms and conditions of service were unjust or unreasonable or unduly discriminatory or preferential.

The FERC implements the OCSLA pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide non-discriminatory transportation service. The Caesar, Cleopatra, Proteus, and portions of Endymion, Mars and Ursa pipelines are located in the Outer Continental Shelf and are subject to the non-discrimination requirements in the OCSLA.

Safety

Our assets are subject to stringent safety laws and regulations. Our transportation of crude oil, natural gas, refined products and diluent involves a risk that hazardous liquids or flammable gases 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. PHMSA of DOT has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our assets. BSEE of DOI has adopted similar regulations for offshore pipelines under its jurisdiction. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and necessary maintenance or repairs. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

Pipeline safety laws and regulations are subject to change over time. Changes in existing laws and regulations could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition. For example, PHMSA issued the Safety of Hazardous Liquids Pipelines final rule on October 1, 2019. This final rule addressed topics such as: inspections of onshore and offshore pipelines following extreme weather events or natural disasters, periodic assessment of pipelines not currently subject to integrity management, expanded use of leak detection systems, increased use of in-line inspection tools, and other requirements. The new PHMSA rule requires operators of onshore pipeline segments that can accommodate in-line inspection (“ILI”) tools that are not currently subject to integrity management requirements to complete assessments using ILI tools at least once every ten years. The new rule also requires that all hazardous liquids pipelines located in high consequence areas (“HCAs”) or areas that could affect HCAs be capable of accommodating ILI tools within 20 years unless certain limited exceptions apply. Additional rulemakings related to pipeline safety are expected to be issued in the future; for example, in its reauthorization of PHMSA, Congress ordered PHMSA to move forward with certain rulemakings.

For the pipelines we operate (BP2, River Rouge and Diamondback), 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 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 each pipeline. We compare these inspection and testing results with other inspection data to ensure that the highest risk pipelines receive the highest priority for consideration of additional integrity assessments or repairs. We use external coatings and impressed current cathodic protection systems to protect against external corrosion. We conduct all cathodic protection work in accordance with all state and federal regulations, and we regularly monitor, test, and record the effectiveness of these corrosion inhibiting systems.

Mars, the Mardi Gras Joint Ventures, and Ursa are operated in a similar manner by an affiliate of Shell. KM Phoenix's terminalling assets are operated in a similar manner by an affiliate of Kinder Morgan.

Security

We are subject to the Transportation Security Administration's Pipeline Security Guidelines, and some of the pipelines have been identified as Critical Infrastructure Assets. Further, the SP 89E platform associated with Proteus is subject to Maritime Transportation Safety Act requirements through the U.S. Coast Guard. We have an internal program of inspection designed to monitor and enforce 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.

BP experiences cyber attacks and other attempts to gain unauthorized access to their systems on a regular basis. As we use BP's systems to support our operations as provided in the omnibus agreement, we are exposed to the same attempts to gain unauthorized access. We may experience future security issues, whether due to employee error or malfeasance or system errors or vulnerabilities in BP's or other parties' systems, which could result in significant legal and financial exposure. Government inquiries and enforcement actions, litigation, and adverse press coverage could harm our business. We and BP may be unable to anticipate or detect attacks or vulnerabilities or implement adequate preventative measures. Attacks and security issues could also compromise trade secrets and other sensitive information, harming our business.

While BP has dedicated significant resources to security incident response capabilities, including dedicated worldwide incident response teams to protect our systems, BP's and our response process, particularly during times of a natural disaster or pandemic (including COVID-19), may not be adequate, may fail to accurately assess the severity of an incident, may not respond quickly enough, or may fail to sufficiently remediate an incident. As a result, we may suffer significant legal, reputational, or financial exposure, which could harm our business, financial condition, and operating results.

Environmental Matters

General. Our operations are subject to federal, state and local laws, regulations and ordinances relating to the protection of the environment and natural resources. Among other things, these laws and regulations govern the emission or discharge of pollutants into or onto the land, air and water, the handling and disposal of solid and hazardous wastes and the remediation of contamination. Compliance with existing and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, operate and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe they do not affect our competitive position, as the operations of our competitors are similarly affected. These laws and regulations are subject to changes, or to changes in the interpretation of such laws and regulations, by regulatory authorities, and continued and future compliance with such laws and regulations may require us to incur significant expenditures. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions limiting our operations, investigatory or remedial liabilities or construction bans or delays in the construction of additional facilities or equipment. Additionally, a release of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expenses, including costs to comply with applicable laws and regulations and to resolve claims by third parties for personal injury or property damage, or by the U.S. federal government or state governments for natural resources damages. These impacts could directly and indirectly affect our business and have an adverse impact on our financial position, results of operations, and liquidity. We cannot currently determine the amounts of such future impacts.

Air Emissions. Our operations are subject to the federal Clean Air Act and its regulations and comparable state and local statutes and regulations in connection with air emissions from our operations. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources that are already constructed. These permits may require controls on our air emission sources, and we may become subject to more stringent regulations requiring the installation of additional emission control technologies.

We cannot predict the potential impact of climate change legislation and regulations to address air emissions in the United States or of any climate-related litigation on our future consolidated financial condition, results of operations or cash flows. However, changes in laws, regulations, policies and obligations relating to climate change, including carbon pricing, could impact our assets, costs, revenue generation and growth opportunities. Refer to Part I, Item 1A. Risk Factors—*Risks Related to Our Business* for additional information.

Waste Management and Related Liabilities. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hydrocarbons, hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control pollution of the environment. These laws generally regulate the generation, storage, treatment, transportation, and disposal of solid and hazardous waste. They also require corrective action, including investigation and remediation, at a facility where such waste may have been released or disposed.

CERCLA. CERCLA and comparable state laws impose liability, without regard to fault or to the legality of the original conduct, on certain classes of persons that contributed to the release of a “hazardous substance” into the environment. These persons include the former and present owner or operator of the site where the release occurred and the transporters and generators of the hazardous substances found at the site.

Under CERCLA, these classes of persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we generate waste that falls within CERCLA’s definition of a “hazardous substance” and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites and any natural resource damages. We also may have similar liabilities under state laws comparable to CERCLA.

RCRA. We also generate solid wastes, including hazardous wastes, that are subject to the requirements of the federal RCRA statute and its implementing regulations, and comparable state statutes. From time to time, the EPA and states consider the adoption of stricter disposal standards for non-hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Significant changes in the regulations could increase our maintenance capital expenditures and operating expenses.

Hydrocarbon Wastes. We currently own and lease properties where hydrocarbons are being or for many years have been handled. Over time, hydrocarbons or waste may have been disposed of or released on or under our properties or on or under other locations where hydrocarbons and wastes were taken for disposal. In addition, many of these properties and locations have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under our control. These properties and hydrocarbons and wastes disposed thereon may be subject to regulation under CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater), or to take actions to prevent further contamination.

Indemnity Under the Omnibus Agreement. Under the omnibus agreement, BP Pipelines will indemnify us for all known and certain unknown environmental liabilities that are associated with the ownership or operation of certain of our assets and due to occurrences on or before October 30, 2017, subject to certain limitations. Indemnification for any unknown environmental liabilities will be limited to liabilities due to occurrences on or before October 30, 2017, which are identified prior to October 30, 2020, and will be subject to an aggregate deductible of $0.5 million before we are entitled to indemnification for losses incurred. Once we meet the deductible, BP Pipelines’ indemnity obligation for environmental claims that are unknown as of October 30, 2017 and litigation claims pending as of October 30, 2017 is capped at $15 million. Indemnification for known environmental liabilities identified in the omnibus agreement is not subject to a deductible; however, BP Pipelines' indemnity obligation for these identified environmental liabilities is capped at $25 million. We will not be indemnified for any spills or releases of hydrocarbons or hazardous materials at our facilities that occur after October 30, 2017, or for any other environmental liabilities resulting from our own operations. In addition, we initially agreed to indemnify BP Pipelines for losses arising out of, or associated with, the ownership, management or operation of the IPO Contributed Assets, whether related to the period before or after October 30, 2017 to the extent BP Pipelines is not required to indemnify us for such losses. Losses for which we will indemnify BP Pipelines pursuant to the omnibus agreement are not subject to a deductible before BP Pipelines is entitled to indemnification. There is no limit on the amount for which we will indemnify BP Pipelines under the omnibus agreement. As a result, we may incur such expenses in the future, which may be substantial.

Water. Our operations can result in the discharge of pollutants, including crude oil, natural gas, refined products and diluent. Regulations under the Clean Water Act, OPA-90 and state laws impose regulatory burdens on our operations. The discharge of pollutants into jurisdictional waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. Army Corps of Engineers (the “Corps”), or a delegated state agency. We obtain discharge permits as required under the National Pollutant Discharge Elimination System program of the Clean Water Act or state laws as needed for maintenance or hydrostatic testing activities. In addition, the Clean Water Act and analogous state laws require coverage under general permits for discharges of storm water runoff from certain types of facilities.

The transportation of crude oil, natural gas, refined products and diluent over and adjacent to water involves risk and subjects us to the liability provisions of and certain regulations issued pursuant to OPA-90 and related state requirements. Among other requirements, OPA-90 requires the owner or operator of a tank vessel or a facility to maintain an emergency plan to respond to releases of oil or hazardous substances. PHMSA and BSEE have promulgated regulations requiring such plans that apply to our onshore and offshore pipelines. With respect to statutory liability, 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. OPA-90 applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA-90 has the potential to adversely affect our operations.

Construction or maintenance of our pipelines may impact “waters of the United States” (“WOTUS”) under the Clean Water Act. A 2015 rule defining the scope of federal jurisdiction over such waters was repealed in December 2019, re-establishing the pre-2015 rule until it was replaced in June 2020 when the EPA’s Navigable Waters Protection Rule, finalized in January 2020, became effective. The Navigable Waters Protection Rule narrows the definition of WOTUS relative to the prior 2015 rulemaking. Legal challenges to both this and prior revisions to the definition of WOTUS are ongoing, and it is possible that the Biden Administration could propose a broader interpretation of the Clean Water Act’s jurisdiction. If the scope of federal jurisdiction over such waters is revised in the future and expands the range of properties subject to the Clean Water Act’s jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which in turn could reduce demand for our services. Regulatory requirements governing wetlands or river crossings (including associated mitigation projects) may result in the delay of our pipeline projects while we obtain necessary permits and may increase the cost of new projects and maintenance activities.

Employee Safety. We are subject to the requirements of the OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. While some of our facilities are in areas that may be designated as habitat for endangered species, to date, we have not experienced any material adverse impacts as a result of compliance with the Endangered Species Act. If current or future-listed endangered or threatened species or critical habitat are located in areas of the underlying properties where we wish to conduct development activities associated with construction, such work could be prohibited or delayed or expensive mitigation may be required. The U.S. Fish and Wildlife Service periodically makes determinations on listing of numerous species as endangered or threatened under the Endangered Species Act. The discovery of previously unidentified endangered species or threatened species or the designation and listing of new endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected area.

National Environmental Policy Act. Major federal actions, such as the issuance of permits associated with construction, can require the completion of certain reviews under the NEPA. NEPA requires federal agencies, including the Corps, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the abandonment of proposed projects. In July 2020, the Council on Environmental Quality finalized revisions to update the NEPA regulations; however, these regulations may be subject to further revision under the Biden Administration. The impact of any changes to the NEPA regulations, if adopted, on our pipeline projects is uncertain.

Seasonality

Demand for crude oil, refined products and diluent generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase demand during the summer and winter months and decrease demand during the spring and fall months. In respect of our midstream systems, we do not expect seasonal conditions to have a material impact on our throughput volumes, as many effects of seasonality on our revenue will be substantially mitigated through the use of our fee-based long-term agreements with BP Products that include minimum volume commitments. Severe or prolonged winters may, however, impact our ability to complete maintenance and construction projects, which may impact our revenues and results of operations.

Title to Real Property Interests and Permits

While there are a limited number of fee-owned properties associated with certain of our pipeline assets, substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property and in some instances these rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that may not have been subordinated to the rights-of-way ("ROW") grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, and state highways and, in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. In some states and under some circumstances, we have the right to seek the use of eminent domain power to acquire rights-of-way and lands necessary for our common carrier pipelines.

Insurance

Our assets are either self-insured or insured with third parties for certain property damage, business interruption and third-party liabilities, and such coverage includes sudden and accidental pollution liabilities, in amounts which management believes are reasonable and appropriate, and excludes named windstorm coverage.

Human Capital Resources

Our operations are conducted through, and our assets are owned by, various subsidiaries. However, neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by BP, BP Pipelines or third parties, but we sometimes refer to these individuals, for drafting convenience only, in this Annual Report as our employees because they provide services directly to us. These operations personnel primarily provide services with respect to the assets we operate: BP2, River Rouge and Diamondback. Mars, the Mardi Gras Joint Ventures, and Ursa are operated by an affiliate of Shell. KM Phoenix is operated by an affiliate of Kinder Morgan. Under the omnibus agreement we are required to reimburse BP for all costs attributable to operating personnel services. A portion of the operations personnel who provide services for our onshore assets are represented by labor unions. We consider our labor relations to be good and have not experienced any material work stoppages or other material labor disputes within the last five years.

Pipeline Control Operations

BP2, River Rouge, and Diamondback, which are operated by BP Pipelines' employees, are controlled from a central control center located in Tulsa, Oklahoma. A fully functional back-up operations center is also maintained and routinely operated throughout the year with the aim of ensuring safe, reliable, and compliant operations. Mars, the Mardi Gras Joint Ventures, and Ursa are operated in a similar manner by an affiliate of Shell. The KM Phoenix storage and terminalling systems are operated by an affiliate of Kinder Morgan.

Website

Our Internet website address is http://www.bpmidstreampartners.com. Information contained on our Internet website is not part of this Annual Report on Form 10-K.

Our Annual Reports 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 these reports, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC's website at http://www.sec.gov. We also post on our website our beneficial ownership reports filed by officers and directors of our general partner, as well as principal security holders, under Section 16(a) of the Exchange Act, corporate governance guidelines, audit committee charter, code of business conduct and ethics, financial code of ethics and information on how to communicate directly with our general partner's Board of Directors.

Item 1A. RISK FACTORS

Investing in our limited partner interests involves a high degree of risk. You should carefully consider all information in this Annual Report on Form 10-K prior to investing in our limited partner interests. In addition to the factors discussed elsewhere in this report, the following risks and uncertainties, some of which have occurred and any of which may occur in the future, could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to pay minimum quarterly distributions to our unitholders may be reduced or the trading price of our units could decline and you could lose all or part of your investment. Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may impair our business, financial condition, results of operations and cash flows.

Risk Factors Summary

Risks Related to the Partnership's Business

Results of Operations and Financial Condition. Our operations and financial condition could be impacted by many risks that are beyond our control, including the following:

- fluctuations in the demand for and price of oil, refined products and other commodities;
- the outbreak of COVID-19 and recent geopolitical developments in the crude oil market;
- BP's transition to an integrated energy company focused on low carbon energy;
- our ability to pay minimum quarterly distributions following the establishment of cash reserves and payment of fees and expenses, including those to our general partner;
- the potential of BP Products' refusal to enter into new minimum volume commitment agreements or termination of such existing agreements under certain conditions;
- our limited control over certain assets owned through joint ventures;
- our ability to obtain capital or financing on satisfactory terms sufficient to fund future expansions;
- our ability to make acquisitions on economically acceptable terms from BP or third parties;
- the exposure of our operations to risks and operational hazards and the potential of events resulting in business interruption or shutdown;
- our ability to maintain current volumes of crude oil, natural gas, refined products or diluent that we transport and our dependence on third-party pipelines, production platforms, refineries, caverns and other facilities to transport, produce, refine and store such volumes;
- our reliance on BP for a substantial majority of the crude oil, natural gas, refined products and diluent that we transport;
- a material decrease in the utilization of and/or demand for products or diluent from the Whiting Refinery;
- the impact of hurricanes and other severe weather disruptions to our offshore pipelines in the Gulf of Mexico;
- the expiration of our environmental indemnification notification period with our general partner;
- cybersecurity breaches and other disruptions or failures of our information systems; and
- restrictions involving our credit facility and any future debt we incur.

Regulatory Matters. Our business, results of operations, cash flows, financial conditions, and future growth could be impacted by the following:

- compliance with complex laws and regulations relating to the protection of the environment and natural resources, the regulation of energy transportation pipeline safety and occupational health and safety;
- compliance with such laws and regulations may result in considerable costs or other constraints on our operations;
- failure to comply with such requirements may result in substantial fines or may require corrective actions, which could likewise have material effects on our operations;
- although environmental laws and regulations address numerous areas, we are subject to particular risks from new or more stringent requirements relating to pipeline safety and climate change, as well as from potentially restricted access to capital as a result of climate change concerns; and
- actions by the Biden Administration may limit the amount of production available to deliver through our pipelines.

Risks Inherent in an Investment in Us

Cash Distributions to Unitholders. Our cash distributions could be impacted by the following:

- cash distributions are not guaranteed and may fluctuate with our performance and other external factors;
- our expectation to distribute a significant portion of our cash available for distribution to our partners;
- limitations on cash available for distribution that are imposed by our cash distribution policy and any modifications or revocations of such policy by our general partner.

Our General Partner. Our stakeholders could be impacted by risks related to our general partner, including:

- the potential that our general partner and its affiliates have conflicts of interest with us and limited duties to us;
- substantial cost reimbursements due to our general partner; and

- the limited voting rights of unitholders in matters related to our general partner.

Tax Risks to our Common Unitholders

- our tax treatment depends on our status as a partnership for federal income tax purposes, and not being subject to a material amount of entity-level taxation. Our cash available for distribution to unitholders may be substantially reduced if we become subject to entity-level taxation as a result of the Internal Revenue Service ("IRS") treating us as a corporation or legislative, judicial or administrative changes, and may also be reduced by any audit adjustments if imposed directly on the partnership;
- even if unitholders do not receive any cash distributions from us, unitholders will be required to pay taxes on their share of our taxable income and a unitholder's share of our taxable income may be increased as a result of the IRS successfully contesting any of the federal income tax positions we take; and
- tax exempt entities and non-U.S. unitholders face unique tax issues from owning our common units that may result in adverse tax consequences to them.

In addition to the factors discussed elsewhere in this report, the following risks and uncertainties, some of which have occurred and any of which may occur in the future, could have a material adverse effect on our business, financial condition, results of operations and cash flows. Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may impair our business, financial condition, results of operations and cash flows.

Risks Related to Our Business

Events outside of our control, including a pandemic such as the global outbreak of COVID-19, and the potential global recession could have a material adverse impact on our financial position, results of operations and cash flows.

In the first quarter of 2020, the COVID-19 outbreak began to spread quickly across the globe. Federal, state and local governments mobilized to implement containment mechanisms and minimize impacts to their populations and economies. Various containment measures, which included the quarantining of cities, regions and countries have resulted in a severe drop in general economic activity and a decrease in energy demand. The risks associated with COVID-19 have also impacted the BP Pipelines workforce and the way we meet our business objectives.

The current commodity price environment may remain depressed based on over-supply, decreasing demand and a potential global economic recession. With decreased demand and the storage and transportation constraints further adding to the pressure on commodities prices, refiners have curtailed output, and producers all over the world – including in the United States – have significantly decreased their capital programs and shut-in production. If these conditions persist beyond 2020, we could continue to see a significant decline in demand for our services with respect to our onshore pipelines if volumes shipped on such pipelines remain below the existing MVCs. The MVC agreements executed on November 3, 2020 provide downside protection to the Partnership albeit at a lower level than in prior years on BP2 and Diamondback.

In addition, it is possible that volumes may be reduced on our offshore pipelines as well, which are not covered by any MVCs. In the short term, there is risk of decreased volumes with respect to the offshore operations if operators take actions to reduce operations in response to demand declines or increasingly limited storage availability or are unable to control COVID-19 infections on platforms and are required to shut-in. In the longer term, there is risk that our customers cease investing in additional offshore projects in a protracted low commodity price environment, which would harm our growth. Our profitability may be significantly affected by this decreased demand and these factors could lead to reductions in our distributions to unitholders.

In addition, the outbreak of COVID-19 could potentially further impact the BP Pipelines workforce. The infection of key personnel, and/or the infection of a significant amount of the BP Pipelines workforce, could have a material adverse impact on our business, financial condition and results of operations. BP employees have been working from home since March 16, 2020, except those deemed critical to the functioning of owned and managed assets. A remote workforce could introduce risks to achieving business objectives and/or the ability to maintain our controls and procedures. For example, the technology required for the transition to remote work increases our vulnerability to cybersecurity threats, including threats of unauthorized access to sensitive information or to render data or systems unusable, the impact of which may have material adverse effects on our business and operations. See *Terrorist or cyber-attacks and threats, or escalation of military activity in response to these attacks, could have a material adverse effect on our business, financial condition or results of operations.*"

In addition to the risks stated above, our operations are subject to additional risks related to the current economic environment caused by the factors discussed above, including:

- our debt service requirements and other liabilities, and restrictions contained in our debt agreements;
- our ability to maintain sufficient cash available for distribution following the establishment of cash reserves and payment of fees and expenses, to enable us to pay minimum quarterly distributions to unitholders;
- unavailability of third-party pipelines, production platforms, refineries, caverns and other facilities interconnected to our pipelines to transport, produce, refine or store crude oil, natural gas, refined products or diluent;
- demand for refined products or diluent, continues to decrease; and
- the risk of further adverse changes to BP's production or development plans, which we are dependent on for a majority of the crude oil, natural gas, refined products and diluent that we transport

The impacts of COVID-19 and the associated drop in consumer demand for refined products has had an unprecedented impact on the global economy, and the pipelines and refined products transportation sector in particular. We are unable to predict the impacts of these events on the global economy and the demand for our services, and as such, these events could have a material impact on our business, financial condition and results of our operations.

BP's new business strategy to pivot from being an international oil company focused on producing resources to an integrated energy company focused on delivering solutions for customers may adversely affect our business, financial condition, results of operations, cash flows, and ability to make cash distributions to our unitholders.

In 2020, BP introduced a new strategy and new business structure, leadership team and core capabilities: operations, customers, low carbon and innovation. As part of this new strategy, BP has publicly disclosed that, within 10 years, BP aims to increase its annual low carbon investment 10-fold, build out an integrated portfolio of low carbon technologies, including renewables, bioenergy and early positions in hydrogen and carbon capture, use and storage. By 2030, BP aims to have developed around 50GW of net renewable generating capacity – a 20-fold increase from 2019 – and to have doubled its consumer interactions to 20 million a day. Over the same period, BP's oil and gas production is expected to reduce by at least one million barrels of oil equivalent a day, or 40%, from 2019 levels. Its remaining hydrocarbon portfolio is expected to be more cost and carbon resilient.

Since we are dependent on BP for a substantial majority of the crude oil, natural gas, refined products and diluent that we transport, and BP plans to reduce its production of such products, we can offer no assurances that we will be able to effectively or efficiently integrate our operations with BP's new business structure and its focus on low carbon energy. If we are unable to integrate our business with BP's new business structure and strategy, or if execution of such business structure and strategy requires more time than expected, our business, results of operations, financial condition and ability to make cash distributions to our unitholders could be adversely affected.

We may not have sufficient cash available for distribution following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay minimum quarterly distributions to our unitholders.

The amount of cash available for distribution we must generate to support the payment for four quarters of minimum quarterly distributions on our common and subordinated units, outstanding as of December 31, 2020, is $110.0 million (or an average of approximately $27.5 million per quarter). However, we may not generate sufficient cash flows each quarter to enable us to maintain or grow our current distribution level, or to pay minimum quarterly distributions. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things, our throughput volumes, tariff rates and fees and prevailing economic conditions. In addition, the actual amount of cash flows we generate will also depend on other factors, some of which are beyond our control, including:

- the amount of our operating expenses and general and administrative expenses, including reimbursements to BP Pipelines and its affiliates with respect to those expenses;
- the amount and timing of capital expenditures and acquisitions we make;
- our debt service requirements and other liabilities, and restrictions contained in our debt agreements;
- fluctuations in our working capital needs;
- decisions made by BP with respect to the levels of production at its refineries that we serve and its obligations under our commercial agreements;
- our entitlements to payments associated with the minimum volume commitments under our commercial agreements with BP Products;
- the amount of cash distributed to us by the entities in which we own a non-controlling interest; and
- the amount of cash reserves established by our general partner.

BP Products is under no obligation to enter into new minimum volume commitment agreements following their respective terms and may terminate its obligations earlier under certain specified circumstances, which could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

BP Products is under no obligation to enter into new minimum volume commitment agreements following their respective terms. Minimum volume commitment agreements for BP2, River Rouge and Diamondback expire in 2023, with an additional Diamondback minimum volume commitment agreement expiring in 2022. In addition, BP Products has the right to terminate these agreements prior to the end of their terms under certain specified circumstances, including (i) if we fail to perform any of our material obligations and fail to correct such non-performance within specified periods, and (ii) in the event of a change of control of our general partner. Minimum volume commitments under these agreements support a substantial portion of our revenues. As a result, any such termination of BP Products' obligations could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders. Please read "Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements."

We own certain assets through joint ventures that we do not operate, and our control of such assets is limited by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint ventures.

We own a (i) 28.5% interest in Mars, a joint venture with certain affiliates of Shell that is operated by an affiliate of Shell, (ii) a 65% managing member interest in Mardi Gras, which owns a 56% ownership interest in Caesar, a 53% interest in Cleopatra, a 65% interest in Proteus and a 65% interest in Endymion, each of which is operated by an affiliate of Shell, (iii) 22.7% interest in Ursa, a joint venture with certain affiliates of Shell that is operated by an affiliate of Shell, and (iv) a 25% interest in KM Phoenix Holdings, a joint venture with certain affiliates of Kinder Morgan that is operated by an affiliate of Kinder Morgan. Through our managing member interest in Mardi Gras, we have the right to vote Mardi Gras' interest in the Mardi Gras Joint Ventures. As we do not operate the assets owned by these joint ventures, our control over their operations is limited by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint ventures. Our ability to make distributions to our unitholders depends on the performance of these joint ventures and their ability to distribute funds to us, and we may be unable to control the amount of cash we will receive from their operations, which could adversely affect our unitholders. More specifically:

- We do not control or operate Mars, Ursa, KM Phoenix or the Mardi Gras Joint Ventures and as a result, we only have limited ability to influence the business decisions of such joint venture entities.
- We do not directly control the amount of cash distributed by Mars, Ursa, KM Phoenix or any of the Mardi Gras Joint Ventures. We only influence the amount of cash distributed through our voting rights over the cash reserves made by such joint venture entities.
- We do not have the ability to unilaterally require Mars, Ursa, KM Phoenix or any of the Mardi Gras Joint Ventures to make capital expenditures.
- Our joint ventures may require us to make additional capital contributions to fund operating and maintenance expenses and maintenance capital expenditures, as well as to fund expansion capital expenditures, which would reduce the amount of cash otherwise available for distribution by us or require us to incur additional indebtedness.

In addition, because we have partial ownership in the joint ventures, we can only exercise limited review and perform limited queries into the accounting performed by the operators. We have no control over the actual day-to-day accounting performed by the operator. If our joint venture partners have control deficiencies in their accounting or financial reporting environments, it may result in reporting our percentage of the financial results for the joint venture that are inaccurate. This could result in a material misstatement in our reported consolidated financial results.

If we are unable to obtain needed capital or financing on satisfactory terms to fund any future expansions of our asset base, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase. Other than our revolving credit facility, we do not have any commitment with any of our affiliates or third parties to provide any direct or indirect financial assistance to us.

We will be required to use cash from our operations, incur borrowings or access the capital markets in order to fund any future expansion capital expenditures. As of December 31, 2020, we have $132 million in available borrowings under our revolving credit facility. The entities in which we own an interest may also incur borrowings or access the capital markets to fund future capital expenditures. Our and their ability to obtain financing or access the capital markets may be limited by our or their financial condition at such time as well as the covenants in our or their debt agreements, general economic conditions and contingencies, or other uncertainties that are beyond our control. The terms of any such financing could also limit our ability to pay distributions to our common unitholders. Incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

If we are unable to make acquisitions on economically acceptable terms from BP or third parties, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders.

Our strategy to grow our business and increase distributions to unitholders is dependent in part on our ability to make acquisitions that result in an increase in cash available for distribution per unit. The consummation and timing of any future acquisitions will depend upon, among other things, whether we are able to:

- identify attractive acquisition candidates;
- negotiate acceptable purchase agreements;
- obtain financing for these acquisitions on economically acceptable terms; and
- outbid any competing bidders.

We have a ROFO pursuant to our omnibus agreement that requires BP Pipelines to allow us to make an offer with respect to the Subject Assets, to the extent BP Pipelines elects to sell those assets (other than to another affiliate of BP Pipelines). BP Pipelines is under no obligation to sell the Subject Assets or offer to sell us additional assets, we are under no obligation to buy any additional interests or assets from BP Pipelines and we do not know when or if BP Pipelines will decide to sell the Subject Assets or make any offers to sell assets to us. We may never purchase all or any portion of the assets subject to the ROFO for several reasons, including the following:

- BP Pipelines may choose not to sell the Subject Assets;
- we may not make acceptable offers for the Subject Assets;
- we and BP Pipelines may be unable to agree to terms acceptable to both parties;
- we may be unable to obtain financing to purchase the Subject Assets on acceptable terms or at all; or
- we may be prohibited by the terms of our debt agreements (including our credit facility) or other contracts from purchasing some or all of the Subject Assets, and BP Pipelines may be prohibited by the terms of its debt agreements or other contracts from selling some or all of the Subject Assets. If we or BP Pipelines must seek waivers of such provisions or refinance debt governed by such provisions in order to consummate a sale of the Subject Assets, we or BP Pipelines may be unable to do so in a timely manner or at all.

We can offer no assurance that we will be able to successfully consummate any future acquisitions, whether from BP or any third parties. If we are unable to make future acquisitions, our future growth and ability to increase distributions may be limited. Furthermore, even if we do consummate acquisitions that we believe will be accretive, they may in fact result in a decrease in cash available for distribution per unit as a result of incorrect assumptions in our evaluation of such acquisitions or unforeseen consequences or other external events beyond our control. Acquisitions involve numerous risks, including difficulties in integrating acquired businesses, inefficiencies and unexpected costs and liabilities.

Our operations are subject to many risks and operational hazards. If a significant accident or event occurs that results in a business interruption or shutdown for which we are not adequately insured, our operations and financial results could be materially and adversely affected.

Our operations are subject to all of the risks and operational hazards inherent in transporting crude oil, natural gas, refined products and diluent, including:

- damages to pipelines, facilities, offshore pipeline equipment and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
- mechanical or structural failures at our or BP Pipelines’ facilities or at third-party facilities on which our customers’ or our operations are dependent, including electrical shortages, power disruptions and power grid failures;
- damages to, loss of availability of and delays in gaining access to interconnecting third-party pipelines, terminals and other means of delivering crude oil, natural gas, refined products and diluent;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack;
- leaks of crude oil, natural gas, refined products or diluent as a result of the malfunction of equipment or facilities;
- unexpected business interruptions;
- curtailments of operations due to severe weather, natural disasters, including hurricanes; acts of terrorism; and
- riots, strikes, lockouts or other industrial disturbances.

For example, on June 13, 2019, a building fire occurred at the Griffith Station on BP2. For additional information, refer to Note 13 - *Commitments and Contingencies* in the Notes to Consolidated Financial Statements.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage, as well as business interruptions or shutdowns of our facilities. Any such event or unplanned shutdown could have a material adverse effect on our business, financial condition and results of operations.

Our profitability and cash flow are dependent on our ability to maintain the current volumes of crude oil, natural gas, refined products or diluent that we transport, which often depend on actions and commitments by parties beyond our control. In order to maintain the volumes transported on our assets, our customers must continually obtain new supplies of crude oil, which is expensive, particularly in offshore Gulf of Mexico.

Our profitability and cash flow are dependent on our ability to maintain the current volumes of crude oil, natural gas, refined products and diluent that we transport. A decision by BP Products not to enter into new minimum volume commitment agreements following their respective terms, or a decision by BP or another shipper to substantially reduce or cease to ship volumes of crude oil, refined products or diluent on our pipelines could cause a significant decline in our revenues. For example, we recognized approximately $9.6 million and $3.6 million of deficiency revenue under the throughput and deficiency agreements with BP Products with respect to BP2 and Diamondback, respectively, for the year ended December 31, 2020. The throughput and deficiency agreement for BP2 expires in December 2023 and contains decreasing volume commitments of 10kbpd per year. The throughput and deficiency agreements for Diamondback expire in June 2022 and December 2023. If volumes on BP2 and Diamondback do not improve or we do not enter into new minimum volume commitment agreements after their expiration, our results will be adversely impacted. Additionally, our minimum volume commitment agreements only support our onshore operations. These agreements terminate at the expiration of their respective terms, and may be terminated earlier under certain specified circumstances, and BP Products is under no obligation to enter into new minimum volume commitment agreements. Please read “Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements.”

In addition, although our offshore assets are generally subject to term agreements or life-of-lease agreements, these agreements generally do not contain minimum volume commitments and many do not have annual cost escalation features. The crude oil and natural gas available to us under these agreements are derived from reserves produced from existing wells, and these reserves naturally decline over time. The amount of crude oil reserves underlying wells in these areas may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Accordingly, to maintain or increase the volume of crude oil transported, or throughput, on our pipelines and cash flows associated with the transportation of crude oil, our customers must continually obtain new supplies of crude oil. In addition, we will not generate revenue under our life-of-lease agreements that do not include guaranteed rates-of-return to the extent that production in the area we serve declines or is shut in.

Finding and developing new reserves, particularly in offshore Gulf of Mexico, is capital intensive, requiring large expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include the prevailing market price of the commodity, the capital budgets of producers, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives, cost and availability of equipment, capital budget limitations or the lack of available capital and other matters beyond our control. Additional reserves, if discovered, may not be developed in the near future or at all.

Additionally, the volumes of crude oil, natural gas, refined products and diluent that we transport depend on the supply and demand for crude oil, gasoline, jet fuel and other refined products in our geographic areas and other factors driving the demand for crude oil, natural gas, refined products and diluent, including competition from alternative energy sources and the impact of new and more stringent regulations and standards affecting the exploration, production and refining industries.

If new supplies of crude oil and natural gas are not obtained, or if the demand for refined products or diluent decreases significantly, there would likely be a reduction in the volumes that we transport. Any such reduction could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

If third-party pipelines, production platforms, refineries, caverns and other facilities interconnected to our pipelines become unavailable to transport, produce, refine or store crude oil, natural gas, refined products or diluent, our revenue and available cash could be adversely affected.

We depend upon third-party pipelines, production platforms, refineries, caverns and other facilities that provide delivery options to and from our pipelines. For example, Mars depends on a natural gas supply pipeline connecting to the West Delta 143 platform to power its equipment and deliver the volumes it transports to salt dome caverns in Clovelly, Louisiana. Additionally, Caesar and Cleopatra do not connect directly to onshore facilities and are dependent upon third-party pipelines for forward shipment onshore**.** Our onshore pipelines are dependent on interconnections with other pipelines and terminals to transport volumes to and from the Whiting Refinery.

Because we do not own these third-party pipelines, production platforms, refineries, caverns or facilities, their continuing operation is not within our control. For example, production platforms in the offshore Gulf of Mexico may be required to be shut in by the BSEE of the DOI following incidents such as loss of well control. If these or any other pipeline or terminal connection were to become unavailable for current or future volumes of crude oil, refined products or diluent due to repairs, damage to the facility, lack of capacity, shut in by regulators or any other reason, or if caverns to which we connect have cracks, leaks or leaching or require shut-in due to changes in law, our ability to operate efficiently and continue shipping crude oil, natural gas, refined products or diluent to major demand centers could be restricted, thereby reducing revenue. As an additional example, the volumes of crude oil that we transport on our BP2 system and refined products and diluent that we distribute on our River Rouge and Diamondback systems depend substantially on the economics of available crude supply for the Whiting Refinery and the economics for refined products and diluent demand in the markets that the pipelines serve. These economics are affected by numerous factors beyond our control.

Any temporary or permanent interruption at any key pipeline or terminal interconnect, at any key production platform or refinery or at caverns to which we deliver could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

Substantially all of the volumes that we transport through our onshore pipelines are dependent on the ongoing operation of the Whiting Refinery. A material decrease in the utilization of and/or demand for refined products or diluent from the Whiting Refinery could materially reduce the volumes of crude oil, refined products or diluent that we handle, which could adversely affect our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

Substantially all of the volumes that we transport through our onshore pipelines are directly or indirectly dependent on the ongoing operation of the Whiting Refinery. For the year ended December 31, 2020, 100% of the volumes that we transported on BP2 and River Rouge were delivered to, or originated from the Whiting Refinery and some of the diluent that Diamondback transported from BP’s Black Oak Junction originated at the Whiting Refinery. Accordingly, any material decrease in the utilization of and/or demand for refined products or diluent from the Whiting Refinery could adversely affect our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

The utilization of the Whiting Refinery is dependent both upon: 1) the price of crude oil or other refinery feedstocks and the price of refined products and diluent and 2) availability of capacity to transport crude and product. Prices are affected by numerous factors beyond our or BP’s control, including the global supply and demand for crude oil, gasoline and other refined products. The availability of capacity to transport crude and products are affected by factors beyond our or BP's control including the availability of capacity to transport Canadian heavy crude from the Alberta oil sands.

In addition to current market conditions, there are long-term factors that may impact the supply and demand of refined products and diluent in the United States. These factors include:

- increased fuel efficiency standards for vehicles;
- more stringent refined products specifications;
- new or changing renewable fuels standards;
- availability of alternative energy sources;
- potential and enacted climate change legislation; and
- increased refining capacity or decreased refining capacity utilization.

If the demand for refined products or diluent, particularly in our primary market areas, decreases significantly, or if there were a material increase in the price of crude oil supplied to the Whiting Refinery without an increase in the value of the products produced by those refineries, either temporary or permanent, which caused production of refined products or diluent to be reduced at the Whiting Refinery, there would likely be a reduction in the volumes of crude oil, refined products and diluent we transport on BP2, River Rouge and Diamondback. Any such reduction could adversely affect our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

Further, the volumes of crude oil that we transport on our BP2 system and refined products and diluent that we distribute on our River Rouge and Diamondback systems depend substantially on the economics of available crude supply for the Whiting Refinery and the economics of refined products and diluent demand in the markets that the pipelines serve. These economics are affected by numerous factors, including maintenance at the Whiting Refinery and apportionment on the Enbridge mainline (which offers all of its capacity on an uncommitted basis), each of which can cause lower throughput on our BP2 system. Volumes are also affected by maintenance and corridor shutdowns due to tie-ins, among other things.

In addition, refineries generally schedule significant maintenance periodically, with additional, less significant maintenance experienced as needed. Maintenance at the Whiting Refinery involve numerous risks and uncertainties. These risks include delays and incurrence of additional and unforeseen costs. The maintenance allows BP to perform upgrades, overhaul and repair of process equipment and materials, during which time a portion of the Whiting Refinery will be under scheduled downtime resulting in a reduced service on our onshore pipelines and as a result, we will generate reduced revenue from the pipelines impacted by such downtime. Further, due to our lack of diversification in assets and geographic location, an adverse development at the Whiting Refinery could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

We are dependent on BP for a substantial majority of the crude oil, natural gas, refined products and diluent that we transport. If BP changes its business strategy, is unable for any reason, including financial or other limitations, to satisfy its obligations under our commercial agreements or significantly reduces the volumes transported through our pipelines, our revenue 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.

Total revenue from BP represented 97.8%, 97.7% and 97.6% of our revenues for the years ended December 31, 2020, 2019 and 2018, respectively. BP is also a material customer of Mars, Ursa, KM Phoenix and each of the Mardi Gras Joint Ventures. BP’s volumes represented approximately 95.2%, 95.1% and 94.9% of the aggregate total volumes transported on the Wholly Owned Assets for the years ended December 31, 2020, 2019 and 2018, respectively. BP’s volumes represented approximately 50.2% of the aggregate total pipeline volumes transported on the Wholly Owned Assets, Mars, the Mardi Gras Joint Ventures, and Ursa combined for the year ended December 31, 2020. It is likely that we will continue to derive a significant portion of our revenue from BP. Therefore, any event, whether in our area of operations or otherwise, that adversely affects BP’s production, financial condition, leverage, results of operations or cash flows may adversely affect our ability to sustain or increase cash distributions to our unitholders. Accordingly, we are indirectly subject to the business risks of BP, some of which are the following:

- the volatility of natural gas, NGL and oil prices, which could have a negative effect on the value of BP’s oil and natural gas properties, its drilling programs or its ability to finance its operations;
- the availability of capital on an economic basis to fund BP’s exploration and development activities;
- BP’s ability to replace reserves, sustain production and begin production on certain leases that may otherwise expire;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production;

BP’s drilling and operating risks, including potential environmental liabilities;

- transportation capacity constraints and interruptions;

adverse effects of governmental and environmental regulation; and

- losses from pending or future litigation.

As discussed above, in the second half of 2020, BP publicly introduced a new strategy, business structure, leadership team and core capabilities: operations, customers, low carbon and innovation. We can offer no assurances that we will be able to effectively or efficiently integrate our operations with BP’s new business structure and its focus on low carbon energy.

Additionally, BP may suffer a decrease in production volumes in the areas serviced by us and is not obligated to use our services with respect to volumes of crude oil, refined products or diluent in excess of the minimum volume commitments under its commercial agreements with us. Please read “Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements.” The loss of a significant portion of the volumes supplied or shipped by BP would result in a material decline in our revenues and our cash available for distribution. For example, we recognized approximately $13.2 million of deficiency revenue under the throughput and deficiency agreements with BP Products with respect to BP2 and Diamondback for the year ended December 31, 2020. Our throughput and deficiency agreement with BP2 will expire December 2023, and our throughput and deficiency agreements with Diamondback will expire June 2021 and December 2023. If volumes on BP2 and Diamondback do not improve or we do not enter into new minimum volume commitment agreements after their expiration, our results will be adversely impacted. In particular, BP Pipelines owns the BP1 pipeline, which also delivers crude oil from Cushing, Oklahoma to the Whiting Refinery. The capacity of BP1, when combined with BP2's 475 kbpd current capacity significantly exceeds Whiting Refinery's nameplate capacity of 430 kbpd. BP Products could choose to ship volumes to Whiting Refinery on BP1 instead of BP2, resulting in a material decline in volumes on BP2. BP may choose to ship on pipelines other than BP2, for example in the case of apportionment on certain pipelines feeding into BP2 or for other commercial reasons.

A shift in our customers' focus away from our areas of operation could result in reduced throughput on our systems and a material decline in our revenues. For example, a decline in production at the Whiting Refinery could materially reduce the volume of refined products transported on River Rouge. If such declines were to occur or continue during a time at which we did not have a commercial agreement with respect to BP2, Diamondback and River Rouge requiring BP to pay us a fee upon failing to satisfy minimum volume commitments, such a decline could result in a significant reduction in revenues that could have a material adverse effect on our results of operations.

Hurricanes and other severe weather conditions, natural disasters or other adverse events or conditions could damage our pipeline systems or disrupt the operations of our customers, which could adversely affect our operations and financial condition.

The operations of our offshore pipelines could be impacted by severe weather conditions or natural disasters, including hurricanes, or other adverse events or conditions. Additionally, such adverse events or conditions could impact our customers, and they may be unable to utilize our pipeline systems. The susceptibility of our assets to storm damage could be aggravated by wetland and barrier island erosion. In addition, neither we nor the entities in which we own an interest that own these offshore pipeline systems carry named windstorm insurance for any of our offshore pipeline systems. Weather-related risks could have a material adverse effect on our ability to continue operations and on our financial condition, results of operations and cash flows.

For example, during the third and fourth quarters of 2020, the operations of our Offshore Pipelines were disrupted by multiple weather events in the Gulf of Mexico, including Hurricanes Laura, Sally, Delta and Zeta. We estimate the gross impact on operations was in the range of 150,000 to 200,000 barrels of oil equivalent per day or $8 million to $10 million to our cash available for distribution, driven primarily by these weather events. Such events have been, and may in the future be material and may cause a serious business disruption or serious damage to our pipeline systems which could affect such systems' ability to transport crude oil and natural gas.

Our environmental indemnification notification period has expired with our general partner.

Under our omnibus agreement, indemnification for any unknown environmental liabilities was limited to liabilities due to occurrences on or before October 30, 2017, which were identified prior to October 30, 2020. We continue to maintain indemnification by our general partner for matters previously discovered. To the extent that unknown environmental liabilities arise relating to prior ownership, the Partnership will be liable. Any such event could have a material adverse effect on our business, financial condition and results of operations.

Our crude oil transportation operations are dependent upon demand for crude oil by refiners concentrated in particular regions, primarily in the Midwest and Gulf Coast.

Any decrease in this demand for crude oil by those refineries or connecting carriers to which we deliver could adversely affect our cash flows. Those refineries', including the Whiting Refinery's, demand for crude oil also is dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

We face intense competition to obtain crude oil, natural gas and refined products volumes.

Our competitors include integrated, large and small independent energy companies who vary widely in size, financial resources and experience. Some of these competitors have capital resources that are greater than ours and control substantially greater supplies of crude oil, natural gas, refined products and diluent.

Even if reserves exist or refined products and diluent are produced in the areas accessed by our facilities, we may not be chosen by the shippers to transport, store or otherwise handle any of these crude oil and natural gas reserves, refined products and diluent. We compete with others for any such volumes on the basis of many factors, including:

- geographic proximity to the production and/or refineries;
- costs of connection;

- available capacity;
- rates;
- logistical efficiency in all of our operations;
- customer relationships; and
- access to markets.

If we are unable to compete effectively for transportation of crude oil, natural gas, refined products or diluent, there would likely be a reduction in the volumes that we transport. Any such reduction could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our assets are either self-insured or insured with third parties for certain property damage, business interruption and third-party liabilities, and such coverage includes sudden and accidental pollution liabilities. We are insured under certain of BP’s corporate insurance policies and losses would be subject to the shared deductibles and limits under those policies.

All of the insurance policies relating to our assets and operations are subject to policy limits. We and the entities in which we own an interest do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Changes in the insurance markets subsequent to the September 11, 2001 terrorist attacks and Hurricanes Katrina, Rita, Gustav, Ike and Harvey have made it more difficult and more expensive to obtain certain types of coverage, and we have elected to self-insure portions of our asset portfolio or insure with third parties. For example, neither we nor the entities in which we own an interest that own our offshore pipeline systems carry named windstorm insurance for any of the offshore pipeline systems. Significant uninsured losses could have a material adverse effect on our business, financial condition and results of operation which could put pressure on our liquidity and cash flows.

We do not own all of the land on which our pipelines are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines are located, and we are, therefore, subject to the possibility of more onerous terms and increased costs to retain necessary land use if we do not have valid leases, licenses or rights-of-way ("ROWs") or if such leases, licenses or rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies, and some of our agreements may grant us those rights for only a specific period of time. Our failure to have or loss of any of these rights, through our inability to renew leases, ROW contracts or otherwise, or inability to obtain leases, licenses or ROWs at reasonable costs could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

We are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our interstate and offshore pipeline operations are subject to pipeline safety regulations administered by the PHMSA of the DOT. These laws and regulations require us to comply with a significant set of requirements for the design, construction, operation, maintenance, inspection and management of our crude oil, natural gas, refined products and diluent pipeline systems.

These requirements are subject to change over time as a result of new pipeline safety laws and additional regulatory actions. For example, in January 2021, Congress reauthorized PHMSA through 2023 and directed the agency to move forward with several regulatory actions.

Changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, PHMSA finalized new pipeline safety rules for hazardous liquids and gas transmission pipelines in October 2019. The Safety of Hazardous Liquids Pipelines final rule addressed topics such as: inspections of onshore and offshore pipelines following extreme weather events and natural disasters, periodic assessment of pipelines not currently subject to integrity management, expanded use of leak detection systems, increased use of in-line inspection tools, and other requirements. This and any future changes in existing laws and regulations could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition. Our actual compliance implementation costs may also be affected by industry-wide demand for the associated contractors and service providers.

Pipeline failures or failures to comply with applicable regulations could result in shut-downs, capacity constraints or operational limitations to our pipelines. Failure to comply with applicable PHMSA regulations can also result in significant fines and penalties. PHMSA has the power to assess penalties of up to $222,504 per violation per day of violation, and up to $2,225,034 for a series of related violations. These amounts, moreover, are subject to future inflation adjustments.

Should any of these risks materialize, they could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Compliance with and changes in environmental, health and safety laws and regulations has a cost impact on our business, and failure to comply with such laws and regulations could have an impact on our assets, costs, revenue generation and growth opportunities. In addition, our customers are also subject to environmental laws and regulations, and any changes in these laws and regulations could result in significant added costs to comply with such requirements and delays or curtailment in pursuing production activities, which could reduce demand for our services. Changes in laws, regulations, policies and obligations relating to climate change, including carbon pricing, could also impact us by adversely affecting the demand for our customers' products.

Our operations are subject to extensive environmental, worker health and safety, and pipeline safety laws and regulations, including those relating to the discharge and remediation of materials in the environment, waste management, natural resource protection and preservation, pollution prevention, pipeline integrity and other safety-related regulations and characteristics and composition of fuels. Numerous governmental authorities, such as the EPA, PHMSA, BSEE, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. Our operations also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater, as well as releases to the Gulf of Mexico from our offshore pipelines. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly owned or operated by us regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. There can be no certainty that our operating management system, or other policies and procedures will adequately identify all process safety, personal safety and environmental risks or that all our operating activities will be conducted in conformance with these systems.

Failure to comply with these laws, regulations and permits may result in joint and several or strict liability or the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and/or the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which our pipeline systems pass, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for remediation costs, personal injury or property damage. In addition, we may experience a delay in obtaining or be unable to obtain required permits or approvals for projects related to our pipeline systems, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenues, which in turn could affect our business, financial condition, results of operations, cash flows and ability to make cash distributions. As new environmental laws and regulations are enacted, the level of expenditures required for environmental matters could increase. Current and future legislative action and regulatory initiatives could result in changes to operating permits, material changes in operations, increased capital expenditures and operating costs, increased costs of the goods we transport, and decreased demand for products we handle that cannot be assessed with certainty at this time. We may be required to make expenditures to modify operations or install pollution control equipment or release prevention and containment systems that could materially and adversely affect our business, financial condition, results of operations and liquidity if these expenditures, as with all costs, are not ultimately reflected in the tariffs and other fees we receive for our services.

Our customers are also subject to environmental laws and regulations that affect their businesses, and changes in these laws or regulations could materially adversely affect their businesses or prospects. In addition, President Biden has announced that climate change will be a focus of his administration. In January 2021, President Biden issued a series of executive orders committing to substantial action on climate change, including, among other things, rejoining the Paris Agreement, calling for the reinstatement or issuance of methane emissions standards for new, modified, and existing oil and gas facilities (including the transmission and storage sectors), suspending the issuance of new leases for oil and gas development in federal lands or waters, and calling for an increased emphasis on climate-related risk across governmental agencies and economic sectors. Any actions that impose greater emissions restrictions or other climate-related regulations could materially adversely affect our customers' businesses or prospects. Separately, in response to concerns related to climate change, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, promoting divestment of fossil fuel equities and pressuring leaders to limit funding to companies in the fossil fuel sector. For example, officials in New York state and New York City have announced their intent to divest the state and city pension funds' holding in fossil fuel companies, and the World Bank has announced that it will no longer finance upstream oil and gas, except in "exceptional circumstances." Additionally, in December 2020, the Federal Reserve Board announced that it has formally joined the Network for Greening the Financial System, a consortium of global financial regulators focused on addressing climate risks. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our customers' business activities, operations and access to capital, which, in turn, could adversely impact their ability to meet their obligations to us. Any changes in laws, regulations, policies, obligations or access to capital that impose significant costs, liabilities or capital restraints on our customers, that result in delays, curtailments or cancellations of their projects, or that reduce demand for their products, could reduce their demand for our services and materially adversely affect our results of operations, financial position or cash flows.

We cannot predict the potential impact of changes to climate change legislation and regulations to address GHG emissions in the United States or of any climate-related litigation on our future consolidated financial condition, results of operations or cash flows; however, changes in laws, regulations, policies and obligations relating to climate change, including carbon pricing, could impact our assets, costs, revenue generation and growth opportunities.

Actions by the Biden Administration may limit the amount of production available to deliver through our pipelines.

The Biden Administration has taken several actions that may limit the extent of oil and gas development on federal lands and waters. On January 20, 2021, the Acting Secretary of the Department of the Interior issued an order temporarily suspending the issuance of new authorizations, including leases and permits, for such activities. On January 27, 2021, President Biden issued an executive order that suspends the issuance of new leases for oil and gas development on federal lands and waters to the extent permitted by law and calls for a review of existing leasing and permitting practices for such activities. All shippers production flowing through our offshore pipelines and expected future production for those pipelines are expected to come from offshore federal leases. Although the order does not apply to existing operations under valid leases, we cannot guarantee that further action will not be taken to curtail oil and gas development on federal lands and offshore waters, which could significantly reduce future volumes on our offshore system.

Subsidence and erosion could damage our pipelines, particularly along the Gulf Coast and offshore and the facilities that serve our customers, which could adversely affect our operations and financial condition.

Our pipeline operations along the Gulf Coast and offshore could be impacted by subsidence and erosion. Subsidence issues are also a concern for our Midwestern pipelines at major river crossings. Subsidence and erosion could cause serious damage to our pipelines, which could affect our ability to provide transportation services or result in leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water, groundwater, or to the U.S. Gulf of Mexico, which could result in liability, remedial obligations, and/or otherwise have a negative impact on continued operations. Additionally, such subsidence and erosion processes could impact our customers who operate along the Gulf Coast, and they may be unable to utilize our services. Subsidence and erosion could also expose our operations to increased risks associated with severe weather conditions and other adverse events and conditions, such as hurricanes and flooding. As a result, we may incur significant costs to repair and preserve our pipeline infrastructure. Such costs could adversely affect our business, financial condition, results of operation or cash flows. Moreover, local governments and landowners have filed several lawsuits in Louisiana against energy companies, alleging that their operations contributed to increased coastal erosion and seeking substantial damages.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any necessary pipeline repair or preventative or remedial measures.

PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines, with enhanced measures required for pipelines located where a leak or rupture could harm a HCA or moderate consequence area ("MCA"). The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could affect an HCA or MCA;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The BSEE has adopted similar pipeline safety and integrity management requirements related to the design, construction, and operation of offshore pipelines under DOI's jurisdiction. At this time, we cannot predict the ultimate cost to maintain compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity inspection and testing. We will continue our pipeline integrity inspection and testing programs to assess and maintain the integrity of our pipelines. The results of these inspections and tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. These expenditures could have a material adverse effect on our results of operations or financial condition. Moreover, changes to pipeline safety laws over time may trigger future regulatory actions, which could lead to our incurring increased operating costs that could also be significant and have material adverse effects on our result of operations or financial condition.

We may be unable to obtain or renew permits necessary for our operations or for growth and expansion projects, which could inhibit our ability to do business.

Our facilities require a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. In addition, we implement maintenance, growth and expansion projects as necessary to pursue business opportunities, and these projects often require similar permits, licenses and approvals. These permits, licenses, approval limits and standards may require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. In some instances, for construction permits, extensive environmental assessments or impact analyses must be completed before a permit can be obtained, which has the potential to result in additional operational delays. Failure to obtain required permits or noncompliance or incomplete documentation of our compliance status with any permits that are obtained may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on our ability to continue operations and on our financial condition, results of operations and cash flows.

Moreover, judicial interpretations of environmental laws and regulations may also impede the issuance of permits for our pipeline projects. For example, following a Montana federal district court's vacatur of the U.S. Army Corps of Engineers' Nationwide Permit ("NWP") 12 for utility line construction under the Clean Water Act and remand to the Corps for non-compliance with the Endangered Species Act ("ESA") in April 2020, there has been a succession of legal actions relating to NWP 12, including the federal court limiting the order by narrowing its applicability to the construction of new oil and gas pipelines, and litigation to stay the order that resulted in the U.S. Supreme Court granting an emergency stay of the order, except as it applies to the pipeline project that was the subject of the original case, Keystone XL. This ongoing litigation has created tremendous uncertainty within the pipeline industry regarding the scope of pipeline activities still allowed to use NWP 12 and concern over the potential long-term harms to pipeline projects throughout the country if the appeal of the district court's order in the Ninth Circuit is unsuccessful. In response to the uncertainty, many companies have reconsidered permitting strategies for projects that were depending on the use of NWP 12. For example, companies have incurred additional costs and project delays by switching to alternative NWPs or the significantly more time-consuming individual permits. In some cases, companies have had to assume some risk in continuing to use NWP 12, particularly for those projects already in the construction phase. In January 2021, the Corps published in the Federal Register its final rule reissuing and modifying a subset of its suite of NWPs, including an amended NWP 12 that authorizes only oil and gas pipeline projects and two new NWPs authorizing other utility line activities; however, the final rule may be subject to legal challenges and the Corps under the Biden Administration may reconsider or overturn the final rule before it becomes effective on March 13, 2021. Taken together, the NWP 12 litigation pending in federal court, the Corps' reissuance of the NWPs, including a restructured NWP 12, and the change in presidential administrations, there is significant uncertainty surrounding the future use of NWP 12. Any disruption in our ability to obtain coverage under NWP 12 or other general permits may result in increased costs and project delays if we are forced to seek individual permits from the Corps. This, in turn, could have an adverse effect on our business, financial condition, and results of operation. We are closely monitoring the litigation and proposed reissuance of NWP 12 and will continue to evaluate the impacts to our business.

Our asset inspection, maintenance or repair costs may increase in the future. In addition, there could be service interruptions due to unforeseen events or conditions or increased downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Our pipelines were constructed over several decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied over time. Depending on the condition and results of inspections, some assets will require additional maintenance, which could result in increased expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

We maintain an integrity management program to monitor the condition of our assets. As there are many factors that are under our influence and others that are not, it is difficult to predict future expenditures related to integrity management inspections and repairs. Additionally, there could be service interruptions associated with these repairs or other unforeseen events. Similarly, laws and regulations may change which could also lead to increased integrity management expenditures. Any increase in these expenditures could adversely affect our results of operations, financial position, or cash flows which in turn could impact our ability to make cash distributions to our unitholders.

The tariff rates of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our revenue and our ability to make distributions to our unitholders.

We provide both interstate and intrastate transportation services for refined products, diluent and crude oil. Our regulated pipelines are required to provide reasonable service to any shipper similarly situated to an existing shipper that requests transportation services on our pipelines. For more information on federal, state and local regulations affecting our business, please read "Business -FERC and Common Carrier Regulations."

Mars, BP2, Diamondback, and River Rouge pipelines provide interstate transportation services that are subject to regulation by FERC under the ICA and Endymion could be subject to intrastate or FERC jurisdiction under certain circumstances in the future. FERC uses prescribed rate methodologies for developing and changing regulated rates for interstate pipelines, including price-indexing with inflation. The indexing method allows a pipeline to increase its rates based on a percentage change in the PPI-FG plus a FERC determined adder and is not based on pipeline-specific costs. If the index falls, we will be required to reduce our rates that are based on the FERC's price indexing methodology if they exceed the new maximum available ceiling rate. However, changes in the index might not be large enough to fully reflect actual increases in our costs. If FERC changes its rate-making methodologies, the new methodologies may result in tariffs that generate lower revenues and cash flows. The FERC's rate-making methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. Any of the foregoing could adversely affect our revenues and cash flows.

Shippers may protest (and FERC may investigate) the lawfulness of existing, new or changed tariff rates. FERC can suspend new or changed tariff rates for up to seven months and can allow new rates to be implemented subject to refund of amounts collected in excess of the rate ultimately found to be just and reasonable. Shippers may also file complaints that existing rates are unjust and unreasonable. If FERC finds a rate to be unjust and unreasonable, it may order payment of reparations for up to two years prior to the filing of a complaint or investigation, and FERC may prescribe new rates prospectively. We may at any time also be required to respond to governmental requests for information, including compliance audits conducted by FERC.

Whether a pipeline provides service in interstate commerce or intrastate commerce, or is otherwise non-FERC-jurisdictional, is highly fact-dependent and determined on a case-by-case basis. We cannot provide assurance that FERC will not at some point assert jurisdiction over some or all currently non-FERC jurisdictional transportation services that we provide based on a determination that a pipeline or pipelines are providing transportation service in interstate commerce and not exclusively intrastate commerce or otherwise non-FERC-jurisdictional. If the FERC were successful in asserting jurisdiction, its ratemaking methodologies may subject us to potentially burdensome and expensive operational, reporting and other requirements.

Caesar provides transportation services that are subject to regulation by FERC pursuant to OCSLA, which includes a duty to provide open and non-discriminatory access on the Caesar facilities. Shippers or other entities may protest the terms or conditions of Caesar's transportation services as being inconsistent with the open access and non-discrimination requirements of OCSLA. If FERC grants such a protest, Caesar may be required to modify the terms or conditions of Caesar's transportation services, which could adversely affect our revenue and our ability to make distributions to our unitholders.

Gas-gathering facilities are generally exempt from FERC's jurisdiction under the NGA. Determinations as to whether a gas pipeline provides FERC-regulated transmission service or non-jurisdictional gathering service have been subject to substantial litigation over time. If FERC were to determine that the services provided by our gas-gathering facilities are not exempt from FERC regulation, then FERC could exercise authority over the rates and terms and conditions of service. Regulation by FERC could increase our operating costs, and could negatively affect our results of operations and financial condition.

State agencies may also regulate the rates, terms and conditions of service for our pipelines offering intrastate transportation services, and such agencies could limit our ability to increase our rates or order us to reduce our rates and pay refunds to shippers. State agencies can also regulate whether a service may be provided or cancelled. If a state agency were to assert jurisdiction over services that are currently non-jurisdictional, we could be subject to these potentially burdensome and expensive requirements.

The FERC and most state agencies generally support light-handed regulation of common carrier refined products, diluent, and crude oil pipelines and have generally not investigated the rates, terms and conditions of service of pipelines in the absence of shipper complaints and may resolve complaints informally. Louisiana's Public Service Commission has a more stringent review of rate increases and may prohibit or limit future rate increases for intrastate movements regulated by Louisiana.

Accepted tariffs do not, however, prevent any other new or prospective shipper, FERC or a state agency from challenging our tariff rates or our terms and conditions of service. Shippers can contest existing rates or terms at any time but must provide the burden of proof supporting their complaint of rates, rules, or discriminatory behavior.

Further, the FERC's and state agencies' actions are subject to court challenge, which may have broader implications for other regulated pipelines.

A successful challenge to any of our rates, or any changes to FERC's approved rate or index methodologies, could adversely affect our revenue and our ability to make distributions to our unitholders. Similarly, if state agencies in the states in which we offer intrastate transportation services change their policies or aggressively regulate our rates or terms and conditions of service, it could also adversely affect our revenue and our ability to make distributions to our unitholders.

Our fixed loss allowance exposes us to commodity prices.

Some of our long-term transportation agreements and tariffs for crude oil shipments include an FLA, including certain agreements and tariffs on BP2, Mars and Endymion.

On Mars and Endymion, we collect FLA to reduce our exposure to differences in crude oil measurement between origin and destination meters, which can fluctuate. With respect to Mars, this arrangement exposes us to risk of financial loss in some circumstances when the crude oil is received from a third party and there is a difference between our measurement and theirs; it is not always possible for us to completely mitigate the measurement differential. If the measurement differential exceeds the fixed loss allowance, the pipeline must make the customer whole for the difference in measured crude oil. Additionally, on our Mars and Endymion pipelines, we take title to any excess product that we transport when product losses are within the allowed levels, and we sell that product several times per year at prevailing market prices. This allowance oil revenue is subject to more volatility than transportation revenue, as it is directly dependent on our measurement capability and prevailing commodity prices at the time of sale.

On BP2, we do not take physical possession of the allowance oil as a result of our services, due to lack of storage associated with this asset. Accordingly, on BP2, we settle allowance oil receivables monthly at prices reflective of the current market conditions. Allowance oil revenue accounted for 4.5%, 8.0%, and 7.5% of our total revenue in 2020, 2019 and 2018, respectively.

If we lose any of our key personnel, through attrition or reinvention, our ability to manage our business and continue our growth could be negatively impacted.

We depend on our senior management team and key technical personnel. If their services are unavailable to us for any reason, we may be required to hire other personnel to manage and operate our company and to develop our products and technology. We cannot assure you that we would be able to locate or employ such qualified personnel on acceptable terms or at all.

In the second half of 2020, BP introduced a new business structure, leadership team and core capabilities. As part of the program to reinvent the company, BP has publicly disclosed the company would generate $2.5 billion of pre-tax cash cost savings by year end 2021. This includes a global workforce reduction of 15% or approximately 10,000 positions. Significant impacts are expected to affect senior levels, with the number of group leaders expected to be reduced by one-third. Front-line operational staff are not expected to be impacted.

We depend on our senior management team and key technical personnel. If their services are unavailable to us for any reason, we may be required to hire other personnel to manage and operate our company partnership and to develop our products and technology. This may require us to renegotiate our omnibus agreement with BP Pipelines, which currently provides for general and administrative services, in addition to other management and maintenance costs. Refer to Part III, Item 13 — "*Omnibus Agreement*" for additional information.

For example, during the third and fourth quarters of 2020, a number of people on our management team retired.

- On September 18, 2020, Gerald Maret informed the Secretary of the general partner of his intent to retire from his position as Chief Operating Officer, effective December 31, 2020.

- On October 2, 2020, Brian Smith informed the Secretary of the general partner of his intent to retire from his position as a director of the general partner, effective October 8, 2020.

- On October 2, 2020, Craig Coburn informed the Secretary of the general partner of his intent to retire from his position as a director and Chief Financial Officer of the general partner, effective February 28, 2021.

These retirements were not due to any disagreement with the Partnership on any matter relating to the Partnership's operations, policies or practices. In response to this reorganization, the Board of Directors of our general partner announced new appointments to the management team. We cannot assure you that in the future we would be able to locate or employ such qualified personnel on acceptable terms or at all. Any such event could have a material adverse effect on our business, financial condition and results of operations.

Terrorist or cyber-attacks and threats, or escalation of military activity in response to these attacks, could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, or escalation of military activity in response to these attacks, may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. A breach or failure of our digital infrastructure due to intentional actions such as cyber-attacks, negligence or other reasons, could seriously disrupt our operations and could result in the loss or misuse of data or sensitive information, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches and potential legal liability.

Strategic targets, such as energy-related assets and transportation assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the United States. We do not maintain specialized insurance for possible liability or loss resulting from a cyber-attack on our assets that may shut down all or part of our business. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital including our ability to repay or refinance debt. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Restrictions in our revolving credit facility could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

We entered into a revolving credit facility in connection with our IPO. Our revolving credit facility limits our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances; and
- incur certain liens or permit them to exist.

Our revolving credit facility contains covenants requiring us to maintain certain financial ratios. The provisions of our revolving credit facility may affect our ability to obtain future financing and to pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations-Capital Resources and Liquidity."

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt depends upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, investments or capital expenditures, selling assets or issuing equity. We may not be able to effect any of these actions on satisfactory terms or at all.

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

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and 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 the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

The lack of diversification of our assets and geographic locations could adversely affect our ability to make distributions to our common unitholders.

We rely on revenue generated from our pipelines, which are primarily located offshore in the Gulf of Mexico and onshore in the mid-western U.S. Due to our lack of diversification in assets and geographic location, an adverse development in our businesses or areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in demand for crude oil, natural gas, refined products and diluent, could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

If we are deemed an "investment company" under the Investment Company Act of 1940, it could have a material adverse effect on our business and the price of our common units.

Our assets include partial ownership interests in Mars, Ursa, KM Phoenix and Mardi Gras, as well as wholly owned pipelines. If a sufficient amount of our assets, or other assets acquired in the future, are deemed to be "investment securities" within the meaning of the Investment Company Act of 1940, we may have to register as an "investment company" under the Investment Company Act, claim an exemption, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights. Registering as an "investment company" could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage, and require us to add additional directors who are independent of us or our affiliates. The occurrence of some of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

Risks Inherent in an Investment in Us

BP Holdco owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including BP Pipelines, may have conflicts of interest with us and have limited duties to us, and they may favor their own interests to our detriment and that of our unitholders.

BP Holdco, a wholly owned subsidiary of our sponsor, BP Pipelines, owns and controls our general partner and appoints all of the directors of our general partner. Although our general partner has a duty to manage us in a manner that it believes is not opposed to our interest, the executive officers and certain of the directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to BP Holdco. In addition, all of our executive officers and certain of our directors have a fiduciary duty to BP Pipelines or its affiliates due to their position as officers and directors of BP Pipelines or its affiliates. Therefore, conflicts of interest may arise between BP Holdco, BP Pipelines or any of their respective affiliates, including our general partner, on the one hand, and us or any of our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include the following situations, among others:

- our general partner is allowed to take into account the interests of parties other than us, such as BP Holdco and BP Pipelines, in exercising certain rights under our partnership agreement;
- neither our partnership agreement nor any other agreement requires BP Holdco or its affiliates (including BP Pipelines) to pursue a business strategy that favors us;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties and limits our general partner's liabilities, which restricts the remedies available to our unitholders for actions that, without such 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;
- disputes may arise under agreements pursuant to which BP Pipelines and its affiliates are our customers;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any cash expenditure and whether an expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash from operating surplus that is distributed to our unitholders;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our partnership agreement permits us to distribute up to $110.0 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 on the incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with 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 common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations that it and its affiliates owe to us;
- 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 or the unitholders. This election may result in lower distributions to the common unitholders in certain situations.

In addition, we may compete directly with BP Pipelines and entities in which it has an interest for acquisition opportunities and potentially will compete with these entities for new business or extensions of the existing services provided by us. Please read "BP Pipelines and other affiliates of our general partner may compete with us."

The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all.

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we intend to distribute quarterly at least $0.2625 per unit on all of our units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses, including payments to our general partner and its affiliates. However, the board of directors of our general partner may change such policy at any time at its discretion and could elect not to pay distributions for one or more quarters.

In addition, our partnership agreement does not require us to pay any distributions at all. Accordingly, investors are cautioned not to place undue reliance on the permanence of such a policy in making an investment decision. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amounts of distributions to our unitholders. The amount of distributions we make, if any, and the decision to make any distribution at all will be determined by the board of directors of our general partner, whose interests may differ from those of our common unitholders. Our general partner has limited duties to our unitholders, which may permit it to favor its own interests or the interests of BP Holdco or BP Pipelines or their affiliates to the detriment of our common unitholders.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements between us and third parties so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner, and our partnership agreement provides that our general partner may limit its liability without breaching our general partner's duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

We expect to distribute a significant portion of our cash available for distribution to our partners, which could limit our ability to grow and make acquisitions.

We plan to distribute most of our cash available for distribution, which may cause our growth to proceed at a slower pace than that of businesses that reinvest their 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. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the cash that we have available to distribute to our unitholders.

Our general partner will be required to deduct Estimated Total Maintenance Spend from our operating surplus, which may result in less cash available for distribution to unitholders from operating surplus than if actual Total Maintenance Spend (total maintenance expenses and maintenance capital expenditures) were deducted.

We track Total Maintenance Spend on an ongoing basis, which represents the sum of maintenance expenses and maintenance capital expenditures in any given financial reporting period. Collectively these expenditures are made to maintain over the near and long term our operating capacity and operating income. Our partnership agreement requires our general partner to deduct Estimated Total Maintenance Spend, rather than actual Total Maintenance Spend, from operating surplus in determining cash available for distribution from operating surplus.

The amount of Estimated Total Maintenance Spend deducted from operating surplus will be subject to review and change by our general partner's board of directors at least once a year. Our partnership agreement does not cap the amount of Estimated Total Maintenance Spend that our general partner may estimate, and such estimate is intended to represent the average annual Total Maintenance Spend on a three-year basis, as fluctuations in actual amounts can vary substantially in any given year. In years when our Estimated Total Maintenance Spend is higher than actual Total Maintenance Spend, the amount of cash available for distribution to unitholders from operating surplus will be lower than if actual Total Maintenance Spend had been deducted from operating surplus. On the other hand, if our general partner underestimates the appropriate level of Estimated Total Maintenance Spend, we will have more cash available for distribution from operating surplus in the short term but will have less cash available for distribution from operating surplus in future periods when we have to increase our Estimated Total Maintenance Spend to account for the previous underestimation.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our units.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. 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, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder agrees to be bound by our partnership agreement and approves the elimination and replacement of fiduciary duties discussed above.

Because our partnership agreement contains provisions that replace the standards to which our general partner would otherwise be held by state fiduciary duty law, it restricts the remedies available to holders of our units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Because our partnership agreement contains provisions that replace the standards to which our general partner would otherwise be held by state fiduciary duty law, it restricts 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 generally required to make such determination, or take or decline to take such other action, in good faith, meaning that it believed its actions or omission were not opposed to the interests of the partnership, and will not be subject to any higher standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner and its officers and directors will not be liable for monetary damages or otherwise 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 such losses or liabilities were the result of conduct in which our general partner or its officers or directors engaged in bad faith, meaning that they believed that the decision was opposed to the interest of the partnership or, with respect to any criminal conduct, with knowledge that such conduct was unlawful; and
- our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is:
    - approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval; or
    - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, other than one where our general partner is permitted to act in its sole discretion, any determination by our general partner must be made in good faith, meaning that it believed its actions or omissions were not opposed to the interests of the partnership. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our partnership agreement provides that the conflicts committee of the board of directors of our general partner may be comprised of one or more independent directors. For example, if as a result of resignation, disability, death or conflict of interest with respect to a party to a particular transaction, only one independent director is available or qualified to evaluate such transaction, your interests may not be as well served as if the conflicts committee acted with at least two independent directors. A single-member conflicts committee would not have the benefit of discussion with, and input from, other independent directors.

BP Pipelines and other affiliates of our general partner may choose other common carriers for supply.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner, engaging in activities incidental to its ownership interest in us and providing management, advisory, and administrative services to its affiliates or to other persons. However, affiliates of our general partner, including BP Pipelines, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. For example, BP Pipelines owns the BP1 pipeline, which also delivers crude oil from Cushing, Oklahoma to the Whiting Refinery. The capacity of BP1, when combined with BP2's 475 kbpd current capacity, significantly exceeds Whiting Refinery's nameplate capacity of 430 kbpd. BP Products could choose to ship volumes to the Whiting Refinery on BP1 instead of BP2, resulting in a material decline in volumes on BP2. If such decline in volumes on BP2 were to occur or continue following the expiration of BP's obligation with respect to minimum volume commitments on BP2, such a decline could result in a significant reduction in revenues that could have a material adverse effect on our results of operations. BP may choose to ship on pipelines other than BP2, for example in the case of apportionment on certain pipelines feeding into BP2 or for other commercial reasons.

Pursuant to 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 and directors and those of BP Pipelines. 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.

The fees and reimbursements due to our general partner and its affiliates, including BP Pipelines, for services provided to us or on our behalf will reduce our cash available for distribution. In certain cases, the amount and timing of such reimbursements will be determined by our general partner and its affiliates, including BP Pipelines.

Pursuant to our partnership agreement, we will reimburse our general partner and its affiliates, including BP Pipelines, for costs and expenses they incur and payments they make on our behalf. Pursuant to the omnibus agreement and subsequent adjustments, we pay BP Pipelines a fee equal to $15.5 million per year beginning on January 1, 2021, payable in equal monthly installments, for general and administrative services, and, in addition, to reimburse personnel and other costs related to the direct operation, management and maintenance of the assets. Our general partner, in good faith, may adjust the administrative fee to reflect, among others, any change in the level or complexity of our operations, a change in the scope or cost of services provided to us, inflation or a change in law or other regulatory requirements, the contribution, acquisition or disposition of our assets or any material change in our operation activities. In addition, pursuant to the omnibus agreement, we will reimburse our general partner for payments to BP Pipelines and its affiliates for other expenses incurred by BP Pipelines and its affiliates on our behalf to the extent the fees relating to such services are not included in the general and administrative services fee. Each of these payments will be made prior to making any distributions on our common units. The reimbursement of expenses and payment of fees to our general partner and its affiliates will reduce our cash available for distribution. There is no limit on the fee and expense reimbursements that we may be required to pay to our general partner and its affiliates. Refer to Part III, Item 13 — "*Omnibus Agreement*" for additional information.

The holder or holders of our incentive distribution rights may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to the incentive distribution rights, without the approval of the conflicts committee of our general partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

The holder or holders of a majority of our incentive distribution rights (initially our general partner) have the right to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be calculated equal to an amount equal to the prior cash distribution per common unit for the fiscal quarter immediately preceding the reset election (which amount we refer to as 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 equal to the number of common units that would have entitled the holder to an aggregate quarterly cash distribution for the quarter prior to the reset election equal to the distribution on the incentive distribution rights for the quarter prior to the reset election.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per unit without such conversion. However, our general partner may transfer the incentive distribution rights at any time. It is possible that our general partner or a transferee could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the incentive distribution rights expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the incentive distribution rights may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the incentive distribution rights and may therefore desire to be issued our common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience reduction in the amount of cash distributions that they would have otherwise received had we not issued new common units to the holders of the incentive distribution rights in connection with resetting the target distribution levels.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Compared to the holders of common stock in a corporation, unitholders have limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by BP Holdco, as a result of it owning our general partner, and not by our unitholders. Please read "Directors, Executive Officers, and Corporate Governance" and "Certain Relationships and Related Party Transactions, and Director Independence." Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

If you are a non-eligible holder, your common units may be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common units. Eligible holders are limited partners whose, or whose owners', federal income tax status does not have or is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or a similar regulatory body, as determined by our general partner with the advice of counsel. Ineligible holders are limited partners (a) who are not an eligible holder or (b) whose nationality, citizenship or other related status would create a substantial risk of cancellation or forfeiture of any property in which we have an interest, as determined by our general partner with the advice of counsel. If you are an ineligible holder, in certain circumstances as set forth in our partnership agreement, your units may be redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

If our unitholders are dissatisfied with the performance of our general partner, they have limited ability to remove our general partner. Unitholders are currently unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. Our general partner may not be removed except for cause by a vote of the holders of at least 66 $^{2}/_{3}$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. BP Holdco owns an aggregate of 54.4% of our common units as of February 24, 2021.

Our general partner interest or the control 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 without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owner of our general partner to transfer its membership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with its own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our general partner. This effectively permits a "change of control" without the vote or consent of the unitholders.

The incentive distribution rights may be transferred to a third party without unitholder consent.

Our general partner may transfer the incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers the incentive distribution rights to a third party, our general partner would not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of BP Pipelines accepting offers made by us relating to assets owned by BP Pipelines, as it would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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

If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner, its affiliates or we will have the right, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act. As of February 24, 2021, BP Holdco owned 54.4% of our common units.

We may issue an unlimited number of additional partnership interests, including units ranking senior to the common units, without unitholder approval, which would dilute existing unitholder ownership interests.

Our partnership agreement authorizes us to issue an unlimited number of additional limited partner interests at any time without the approval of our unitholders. The issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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 the common units may decline.

There are no limitations in our partnership agreement on our ability to issue units ranking senior to the common units.

In accordance with Delaware law and the provisions of our partnership agreement, we may issue additional partnership interests that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of units of senior rank may (i) reduce or eliminate the amount of cash available for distribution to our common unitholders; (ii) diminish the relative voting strength of the total common units outstanding as a class; or (iii) subordinate the claims of the common unitholders to our assets in the event of our liquidation.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets, including sales by BP Holdco or other large holders.

As of February 24, 2021, we have 104,778,502 common units and no subordinated units outstanding. All of the subordinated units converted into common units on a one-for-one basis at the end of the subordination period. Sales by BP Holdco or other large holders of a substantial number of our common units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. In addition, we have agreed to provide registration rights to BP Holdco. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold. Alternatively, we may be required to undertake a future public or private offering of common units and use the net proceeds from such offering to redeem an equal number of common units held by BP Holdco.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our general partner and 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 designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which would limit our unitholders' ability to choose the judicial forum for disputes with us or our general partner's directors, officers or other employees. Our partnership agreement also provides that any unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such unsuccessful action.

Our partnership agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners, (4) asserting a claim arising pursuant to any provision of the Delaware Act or (5) asserting a claim against us governed by the internal affairs doctrine. In addition, if any unitholder brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such person shall be obligated to reimburse us and our affiliates for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. Our partnership agreement also provides that each limited partner waives the right to trial by jury in any such claim, suit, action or proceeding. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations, provisions and potential reimbursement obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us and our general partner's directors and officers.

The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.

The market price of our common units is influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- the other factors described in these "Risk Factors."

Unitholders' 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 without 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 of the other states in which we do business. A unitholder could be liable for any and all of our obligations as if a unitholder were a general partner if a court or government agency were to determine that (i) we were conducting business in a state but had not complied with that particular state's partnership statute; or (ii) a unitholder's right to act with other unitholders to remove or replace our 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 liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Act, we may not make a distribution to our 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. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

The NYSE does not require a publicly traded partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

Our common units are listed on the NYSE under the symbol BPMP. As a publicly traded 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 stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes and not being subject to a material amount of entity-level taxation. If the IRS were to treat us as a corporation for federal income tax purposes, or if we become subject to entity-level taxation for state tax purposes, our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations and current Treasury Regulations, we believe we satisfy the qualifying income requirement. However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. We currently own assets and conduct business in several states that impose a margin or franchise tax, and the State of Illinois, where Diamondback terminates, currently imposes an income-based replacement tax. In the future, we may expand our operations. Imposition of a similar tax on us in other jurisdictions that we may expand to could substantially reduce our cash available for distribution to our unitholders. Our partnership agreement provides that if a law is enacted or 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 U.S. federal, state, local or foreign income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law or interpretation on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied 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 changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

Our general partner may elect to convert or restructure the partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent.

Under our partnership agreement, our general partner may, without unitholder approval, cause the partnership to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal or applicable state and local income tax purposes, whether by election of the partnership or conversion of the partnership or by any other means or methods. The general partner may take this action if it believes it is adverse to our interests (i) for us to continue to be characterized as a partnership for U.S. federal or applicable state and local income tax purposes or (ii) for common units held by unitholders other than our general partner and its affiliates not to be converted into or exchanged for an interest in an entity taxed as a corporation or at the entity level for U.S. federal or applicable state or local tax purposes whose sole asset is an interest in us. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may vary depending on the unitholder's particular situation and may vary from the tax liability of our general partner and BP Pipelines. In addition and as part of such determination, our general partner and its affiliates may choose to retain their partnership interests in us and cause our interests held by other persons to be exchanged for interests in a new entity, taxable as a corporation or subject to entity-level taxation for U.S. federal or applicable state or local tax purposes whose sole assets are interests in us. Our general partner has no duty or obligation to make any such determination or take any such actions, and may decline to do so in its sole discretion and free from any duty to our limited partners.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. 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 of 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. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information packet to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Even if unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Unitholders are required to pay U.S. federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due from them with respect to that income.

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

If a unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder’s tax basis in those common units. Because distributions in excess of a unitholder’s allocable share of our net taxable income decrease its tax basis in such unitholder’s common units, the amount, if any, of such prior excess distributions with respect to the units a unitholder sells will, in effect, become taxable income to a unitholder if it sells such units at a price greater than its tax basis in those units, even if the price such unitholder receives is less than its original cost. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if a unitholder sells its units, a unitholder may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from a unitholder’s sale of our units, whether or not representing gain, may be taxed as ordinary income to such unitholder due to potential recapture items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder’s adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the “amount realized” by the transferor unless the transferor certifies that it is not a foreign person. While the determination of a partner’s “amount realized” generally includes any decrease of a partner’s share of the partnership’s liabilities, recently issued Treasury regulations provide that the “amount realized” on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner’s share of a publicly traded partnership’s liabilities. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2022, and after that date, if effected through a broker, the obligation to withhold is imposed on the transferor’s broker. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

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

Because we cannot match transferors and transferees of common units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods 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 any sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder’s tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common 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 generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the “Allocation Date”), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets and, (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of common units) may be considered to have disposed of those common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned common units. In that case, the unitholder 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 the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash 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 securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, which could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain recognized 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.

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

In addition to U.S. federal income taxes, our unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, 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 own assets and conduct business in multiple states, which currently impose a personal income tax on individuals, corporations and other entities. 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 United States federal, foreign, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

General Risk Factors

We are exposed to the credit risks, and certain other risks, of our customers, and any material nonpayment or nonperformance by our customers could reduce our ability to make distributions to our unitholders.

We are subject to the risks of loss resulting from nonpayment or nonperformance by our customers. If any of our most significant customers default on their obligations to us, our financial results could be adversely affected. Our customers may be highly leveraged and subject to their own operating and regulatory risks. For certain of our pipelines, we also may have a limited pool of potential customers and may be unable to replace any customers who default on their obligations to us. Therefore, any material nonpayment or nonperformance by our customers could reduce our ability to make distributions to our unitholders.

Any expansion of existing assets or construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our operations and financial condition.

In order to optimize our existing asset base, we intend to evaluate and capitalize on organic opportunities for expansion projects in order to increase revenue on our assets. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost.

We also intend to evaluate and may from time to time expand our existing pipelines, such as by adding horsepower, pump stations or new connections. Any such expansion projects will involve numerous regulatory, environmental, political and legal uncertainties, most of which are beyond our control. The process for obtaining environmental permits has the potential to delay any such expansion projects. In addition, the environmental reviews, permits and other approvals that may be required for such expansion projects may be subject to challenge by third parties which can further delay commencing construction.

Moreover, we may not receive sufficient long-term contractual commitments or spot shipments from customers to provide the revenue needed to support projects, and we may be unable to negotiate acceptable interconnection agreements with third-party pipelines to provide destinations for increased throughput. Even if we receive such commitments or spot shipments or make such interconnections, we may not realize an increase in revenue for an extended period of time.

Potential disruption to our business and operations could occur if we do not address an incident effectively.

Our business and operating activities could be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any major crisis or if we are not able to restore or replace critical operational capacity.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

As disclosed in Note 13 - *Commitments and Contingencies* in the Notes to Consolidated Financial Statements, the Partnership is a party to ongoing legal proceedings in the ordinary course of business, and the disclosure set forth in this footnote relating to certain legal proceedings is incorporated herein by reference.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market for the Partnership's Common Equity

Our common units trade on the NYSE under the symbol “BPMP”. At the close of business on February 12, 2021, there were four unitholders of record of the Partnership's common units.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the quarter or fiscal year ended December 31, 2020 that we have not previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

Market Repurchases

None.

Securities Authorized for Issuance Under Equity Compensation Plans

The Board of Directors for our general partner adopted the BP Midstream Partners LP 2017 LTIP, which permits the issuance of up to 5,502,271 common units. Phantom unit grants have been made to three of the independent directors of our general partner under the LTIP. Refer to Note 15 - *Unit-Based Compensation* in the Notes to Consolidated Financial Statements and Item 12 - *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* for information regarding our equity compensation plan as of December 31, 2020.

Distributions

Cash Distribution Policy

Our partnership agreement provides that our general partner will make a determination as to whether to make a distribution, but our partnership agreement does not require us to pay distributions at any time or in any amount. Pursuant to our cash distribution policy, within 60 days after the end of each quarter, we intend to distribute to the holders of common units on a quarterly basis at least the minimum quarterly distribution of $0.2625 per unit, or $1.05 on an annualized basis, to the extent we have sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. 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 cash distribution policy and the decision to make any distribution will be determined by our general partner, taking into consideration the terms of our partnership agreement. Refer to Part II, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations-Capital Resources and Liquidity—Revolving Credit Facility* for a discussion of the restrictions included in our revolving credit facility that may restrict our ability to make distributions. Refer to Part I, Item 1A. *Risk Factors* for further detail regarding other potential restrictions on our ability to make distributions.

General Partner Interest and Incentive Distribution Rights

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on such interests.

Our general partner currently owns all of our incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of quarterly distributions from operating surplus (as defined in our partnership agreement) after the minimum quarterly distribution and the target distribution levels have been achieved. The maximum distribution of 50% does not include any distributions that our general partner or its affiliates may receive on common units that they own.

Percentage Allocations of Distributions from Operating Surplus

The following table illustrates the percentage allocations of distributions from operating surplus between the unitholders and the holders of our incentive distribution rights based on the specified target distribution levels. The amounts set forth under the column heading "Marginal Percentage Interest in Distributions" are the percentage interests of the holders of our incentive distribution rights and the unitholders in any distributions from operating surplus for the increment of the per unit distribution specified in the column titled "Total Quarterly Distribution Per Unit." The percentage interests set forth below assume there are no arrearages on common units.

	Total Quarterly Distribution Per Unit		Marginal Percentage Interest in Distributions: Unitholders	Marginal Percentage Interest in Distributions: Incentive Distribution Rights Holders
Minimum Quarterly Distribution	up to $0.2625		100 %	— %
First Target Distribution	above $0.2625	up to $0.3019	100 %	— %
Second Target Distribution	above $0.3019	up to $0.3281	85 %	15 %
Third Target Distribution	above $0.3281	up to $0.3938	75 %	25 %
Thereafter	above $0.3938		50 %	50 %

Subordination Period

General

Our partnership agreement provides that, during the subordination period (which we describe below), the common units have the right to receive distributions from operating surplus each quarter in an amount equal to $0.2625 per common unit plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distribution from operating surplus for any quarter until the common units have received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period, there will be sufficient cash from operating surplus to pay the minimum quarterly distribution on the common units.

Subordination Period

Except as described below, the subordination period began on the closing date of the IPO and expired on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ending December 31, 2020, when the following occurred:

- for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date, aggregate distributions from operating surplus equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding in each quarter in each period;
- for the same three consecutive, non-overlapping four-quarter periods, the adjusted operating surplus (as described in our partnership agreement) equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding during each quarter on a fully diluted weighted average basis; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Expiration of the Subordination Period

Accordingly, effective February 12, 2021, the first business day following the payment of the distribution, all of our subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated. The converted common units will participate pro-rata with the other common units in distributions. Refer to Note 17 - *Subsequent Events* in the Notes to Consolidated Financial Statements for additional information.

Item 6. SELECTED FINANCIAL DATA

Not applicable.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Unless otherwise stated or the context otherwise indicates, all references to "we," "our," "us," or similar expressions refer to the legal entity BP Midstream Partners LP (the "Partnership"). The term "our Parent" refers to BP Pipelines (North America), Inc. ("BP Pipelines"), any entity that wholly owns BP Pipelines, indirectly or directly, including BP America Inc. and BP p.l.c. ("BP"), and any entity that is wholly owned by the aforementioned entities, excluding BP Midstream Partners LP.

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information included under Part I, Item 1 and 2. Business and Properties, Part I, Item 1A. Risk Factors and Part II, Item 8. Financial Statements and Supplementary Data. It should also be read together with "Cautionary Note Regarding Forward-Looking Statements" in this report.

This section of this Form 10-K generally discusses 2020 and 2019 items and year-to-year comparisons between 2020 and 2019. Discussions of 2018 items and year-to-year comparisons between 2019 and 2018 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of the Partnerships's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

Partnership Overview

We are a fee-based, growth-oriented master limited partnership formed by BP Pipelines, an indirect wholly owned subsidiary of BP, to own, operate, develop and acquire pipelines and other midstream assets. Refer to Note 1 - *Business and Basis of Presentation* in the Notes to Consolidated Financial Statements.

Business Environment, Market Conditions and Outlook

The impact to the energy industry from the decline in demand for petroleum and petroleum-based products resulting from the response to the global outbreak of COVID-19 have been unprecedented. Additionally, the operations of Mars, Ursa, Caesar, Proteus and Endymion, our offshore crude oil pipeline systems, and Cleopatra, our offshore natural gas pipeline (“Offshore Pipelines”), have been impacted by a record number of storms in a single season. Although our assets have remained operational, the record storm season has negatively impacted our third and fourth quarter results. Management continues to monitor the challenging macro environment. For risks associated with these and other factors, refer to “Item 1A. *Risk Factors*” in this Annual Report.

Management continues to work closely with BP Pipelines, as operator of our assets under the Omnibus Agreement, to ensure appropriate practices are adopted for continued functioning of our assets as well as mitigation strategies for any office or worksite where COVID-19 may be detected.

COVID-19

In the first quarter of 2020, the COVID-19 outbreak spread across the globe. Federal, state and local governments mobilized to implement containment mechanisms and minimize impacts to their populations and economies. Various containment measures, which included the quarantining of cities, regions and countries, have resulted in a significant drop in general economic activity and a resulting decrease in demand for petroleum and petroleum-based products.

In the second and third quarters of 2020, as COVID-19 appeared to decrease or stabilize in certain areas, certain local, regional and national authorities began to loosen such containment measures and restrictions in various locations in an effort to begin economic recovery, among other purposes. While this relaxation of containment measures initially led to an increased demand for petroleum and petroleum-based products through improved general economic conditions, there was also a resurgence of COVID-19 cases in the third quarter. This resurgence continued into the fourth quarter and resulted in the reinstatement of containment measures and restrictions, which has lowered demand for petroleum and petroleum-based products.

Decline in Demand and Potential Impact to Our Operations

The unprecedented supply and demand dynamics created by demand decreases resulting from COVID-19 and supply increases resulting from recent periods of increased production by members of the Organization of Petroleum Exporting Countries and other countries, including Russia ("OPEC+"), beginning in March 2020, have resulted in declines in commodity prices and created volatility, uncertainty, and turmoil in the oil and gas industry. Despite OPEC+ agreeing to cut production in April 2020, such production cuts have yet to offset the decrease in demand resulting from the COVID-19 pandemic and related economic repercussions. As a result, available storage and transportation capacity for production have been limited. It is uncertain whether capital and production cuts will continue and, if so, whether they will be sufficient to offset the continued low demand resulting from the COVID-19 pandemic. Demand and prices may again decline due to the resurgence of the outbreak across the U.S. and other locations across the world and the related social distancing guidelines, travel restrictions, and stay-at-home orders, although the extent of the additional impact on our industry and our business cannot be reasonably predicted at this time.

In the year ended December 31, 2020, we experienced a reduction in volumes on our onshore pipelines as a result of reduced demand. The impacts of this as well as other operational drivers are offset by $13.2 million of deficiency revenue recorded under our MVCs on all onshore pipelines, which extend through December 31, 2023 (and for certain volumes on Diamondback through June 30, 2022).

BP Products has executed new MVC agreements for a three-year term which continues to provide downside protection to the Partnership, however the minimum volume thresholds were reduced from 2020 levels for BP2 and Diamondback. As a result, we could experience a negative financial impact if volumes shipped on our pipelines remain below such minimum commitments beyond 2020 as a result of reduced consumer demand due to the response to the COVID-19 pandemic.

For our offshore joint ventures, we expect demand to be resilient, as offshore projects are larger capital projects planned over many years and less impacted by temporary changes in capital investment. We experienced a decline in volumes on our offshore pipelines throughout 2020; and such decline was primarily due to the short term weather impacts in the Gulf of Mexico and planned maintenance activities. To limit the impact of COVID-19, BP and our other customers, as well as third-party operators of our pipelines, have implemented various protocols for both onshore and offshore personnel; however, these protocols may not prove to be successful. There is risk of decreased volumes with respect to our offshore operations if operators take actions to reduce operations in response to demand declines or increasingly limited storage availability or are unable to control COVID-19 infections on platforms and are required to shut-in. Additionally, we expect the shippers on our offshore pipelines to continue to find buyers for their production; however, they may not be successful.

We have taken steps and continue to actively work to mitigate the evolving challenges and continuing impact of both the COVID-19 pandemic and the industry downturn on our operations and our financial condition. We have also worked with BP Pipelines and the third-party operators of our assets to ensure that COVID-19 response and business continuity plans have been implemented across all of our assets and operations. BP employees, including BP Pipelines personnel, have been working from home since March 16, 2020, except those deemed critical to the functioning of owned and managed assets. For those that are critical and are required to be on-site, protocols have been implemented to protect those employees. Thus far, the need for BP employees to work remotely has not significantly impacted our operations, including use of financial reporting systems, nor has it significantly impacted our internal control environment. We have not incurred, and in the future do not expect to incur, significant expenses related to business continuity. However, our continuing operations and the management of the immediate and contingent safety measures would likely become increasingly difficult if a significant number of BP employees are infected by COVID-19 and the practical difficulties of social distancing impact productivity.

We also continue to monitor our liquidity position. As of December 31, 2020, we had available capacity of $132 million under our unsecured revolving credit facility with an affiliate of BP and $126.9 million in cash and cash equivalents; our only outstanding indebtedness is $468 million under the term loan, with no principal payments due until 2025. We experienced a decline in the price of our common units in 2020, a condition that is consistent across our sector and may impact our ability to access capital markets. We do not have any debt covenants or other lending arrangements that depend upon our unit price. We are in compliance with the covenants contained in both our revolving credit facility and term loan, both of which include the requirement to maintain a consolidated leverage ratio, which is calculated as total indebtedness to consolidated EBITDA, not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. For additional information, refer to “Capital Resources and Liquidity” and Note 9 - *Debt* in the Notes to Consolidated Financial Statements.

We are unable to reasonably predict when, or to what extent, demand for petroleum and petroleum-based products and the overall markets and global economy will stabilize, and the pace of any subsequent recovery for the oil and gas industry. Further, to what extent these events do ultimately impact our business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous evolving factors that cannot be predicted, including the duration of the pandemic.

As noted above, BP Pipelines and the third-party operators of our assets have taken steps and continue to actively work to mitigate the evolving challenges and continuing impact of both the COVID-19 pandemic and the industry downturn on our operations and financial condition. However, given the tremendous uncertainty and turmoil, there is no certainty that the measures we take will be ultimately sufficient.

Weather Impacts

The Atlantic hurricane season this year reached an all-time record in terms of the number of storms in a single season, and during the third and fourth quarters of 2020, the operations of our Offshore Pipelines were disrupted by multiple weather events in the Gulf of Mexico, including Hurricanes Laura, Sally, Delta and Zeta. We estimate the gross impact on operations was in the range of 150,000 to 200,000 barrels of oil equivalent per day or $8 million to $10 million to our cash available for distribution, driven primarily by these weather events. Such events have been, and may in the future be material and may cause a serious business disruption or serious damage to our pipeline systems which could affect such systems’ ability to transport crude oil and natural gas.

How We Generate Revenue

Onshore Assets

We generate revenue on our onshore pipeline assets through published tariffs (regulated by FERC) or contracted rates applied to volumes moved.

We have entered into a throughput and deficiency agreement with our affiliate BP Products North America, Inc. ("BP Products"), an indirect wholly owned subsidiary of BP, for transporting diluent on the Diamondback pipeline under a joint tariff agreement and a dedication agreement with a third-party carrier. These agreements include a minimum volume requirement, under which BP Products has committed to pay us an incentive rate for a fixed minimum volume during the twelve-month running period from July 1, 2017 and each successive twelve-month period thereafter through June 30, 2022, whether or not such volumes are physically shipped through Diamondback. The parties have the option to allow the two agreements to renew annually for one additional year by not sending written notice of termination six months prior to the expiration date.

On November 3, 2020, the Partnership entered into throughput and deficiency agreements with BP Products with respect to volumes transported on BP2, River Rouge and Diamondback. These new agreements have a term of three years beginning January 1, 2021 and expiring December 31, 2023. Under these fee-based agreements, we provide transportation services to BP Products, in exchange for BP Products' commitment to pay us the applicable tariff rates for the minimum monthly volumes, whether or not such volumes are physically shipped by BP Products through our pipelines.

KM Phoenix has terminals located across the United States within key product trading hubs and highly strategic markets that support BP's refining, trading and marketing businesses. KM Phoenix has terminals located near key product trading hubs in New York, Chicago and the San Francisco Bay area. KM Phoenix serves gasoline and diesel needs for New York, Chicago, San Francisco, St Louis, Atlanta, Baltimore, Indianapolis, Cincinnati and Dayton, Ohio. KM Phoenix provides storage for production from BP's three refineries. Seven of KM Phoenix's terminals are supplied directly by BP's refineries with four terminals directly supplied from BP's Whiting Refinery. KM Phoenix generates revenue primarily from truck rack throughput, tank leasing, butane blending and pipeline transshipments.

Offshore Assets

Many of the contracts supporting our offshore assets include fee-based life-of-lease transportation dedications and require producers to transport all production from the specified fields connected to the pipeline for the life of the related oil lease without a minimum volume commitment. This agreement structure means that the dedicated production cannot be transported by any other means, such as barges or another pipeline. The Mars system has a combination of FERC-regulated tariff rates, intrastate rates, and contractual rates that apply to throughput movements and inventory management fees for excess inventory, and certain of those rates may be indexed with the FERC rate. Two of the Mars agreements also include provisions to guarantee a return to the pipeline to enable the pipeline to recover its investment, despite the uncertainty in production volumes, by providing for an annual transportation rate adjustment over a fixed period of time to achieve a fixed rate of return. The calculation for the fixed rate of return is based on actual project costs and operating costs. At the end of the fixed period, the rate will be locked in at a rate no greater than the last calculated rate and adjusted annually thereafter at a rate no less than zero percent and no greater than the FERC index.

The Proteus and Caesar pipelines have an order from the FERC declaring them to be contract carriers with negotiated rates and services. On Proteus and Caesar, the fees for the anchor shippers, which account for a majority of the volumes dedicated to Proteus and Caesar, respectively, were set for the life of the lease over the original lease volumes dedicated to Proteus and Caesar, and are not subject to annual escalation under their oil transportation contracts. The shippers have firm space that varies annually corresponding to their requested maximum daily quantity forecasts. The majority of our revenues on these pipelines are generated by our anchor shippers based on the specified fee for all transported volumes covered by oil transportation contracts with each shipper. Contracts entered into in connection with later connections to Proteus and Caesar may have different terms than the anchor shippers, including rates that vary with inflation.

Cleopatra is also a contract carrier. Each shipper on Cleopatra has a contract with negotiated rates. The rates are fixed for the anchor shippers' dedicated leases, are not subject to annual escalation and generate the majority of Cleopatra's revenues. Contracts for field connections for other shippers contain a variety of rate structures.

Endymion is currently a contract carrier. However, it could be subject to intrastate or FERC jurisdiction under certain circumstances in the future. Endymion generates the majority of its revenues from contractual fees applied to the transportation of oil into storage and from fees applied to per barrel movements of oil out of storage (including volume incentive discounts for larger shippers using storage). The rates are fixed for the anchor shippers' agreements, are not subject to annual escalation and generate the majority of Endymion's revenues. Agreements for other shippers may have different terms than the anchor shippers, including rates that may vary with inflation.

Ursa is a crude oil gathering pipeline system that provides gathering and transportation services extending from the Ursa Tension Leg Platform at Mississippi Canyon Block 809 to a connection with the Mars Oil Pipeline system at West Delta Block 143. From West Delta Block 143 oil is transported to Chevron's Fourchon terminal and LOOP's Clovelly terminal.

Fixed Loss Allowance and Inventory Management Fees

The tariffs applicable to BP2 and Mars include a fixed loss allowance ("FLA"). An FLA factor per barrel, a fixed percentage, is a separate fee under the crude oil tariffs to cover evaporation, crude viscosity, temperature differences and other losses in transit. As crude oil is transported, we earn additional income based on the applicable FLA factor and the volume transported by the customer and the applicable prices. Under the tariff applicable to BP2 and Mars, allowance oil related revenue is recognized using the average market price for the relevant type of crude oil during the month the product is transported.

In addition, we are entitled to inventory management fees for Louisiana offshore oil port storage used by Endymion and Mars.

How We Evaluate Our Operations

Partnership management uses a variety of financial and operating metrics to analyze performance. These metrics are significant factors in assessing operating results and profitability and include: (i) safety and environmental metrics, (ii) revenue (including FLA) from throughput and utilization; (iii) operating expenses and maintenance spend; (iv) Adjusted EBITDA (as defined below); and (v) cash available for distribution (as defined below).

Preventative Safety and Environmental Metrics

We are committed to maintaining and improving the safety, reliability and efficiency of Partnership operations. As noted above, we have worked with BP Pipelines and the third-party operators of our assets to ensure that COVID-19 response and business continuity plans have been implemented across all of our assets and operations. We have implemented reporting programs requiring all employees and contractors of our Parent who provide services to us to record environmental and safety related incidents. The Partnership's management team uses these existing programs and data to evaluate trends and potential interventions to deliver on performance targets. We integrate health, occupational safety, process safety and environmental principles throughout Partnership operations to reduce and eliminate environmental and safety related incidents.

Throughput

We have historically generated substantially all of our revenue under long-term agreements or FERC-regulated generally applicable tariffs by charging fees for the transportation of products through our pipelines. The amount of revenue we generate under these agreements depends in part on the volumes of crude oil, natural gas, refined products and diluent on our pipelines.

Volumes on pipelines are primarily affected by the supply of, and demand for, crude oil, natural gas, refined products and diluent in the markets served directly or indirectly by Partnership assets. Results of operations are impacted by our ability to:

- utilize any remaining unused capacity on, or add additional capacity to, Partnership pipeline systems;
- increase throughput volumes on Partnership pipeline systems by making connections to existing or new third-party pipelines or other facilities, primarily driven by the anticipated supply of and demand for crude oil, natural gas, refined products and diluent;
- identify and execute organic expansion projects; and
- increase throughput volumes via acquisitions.

Storage Utilization

Storage utilization is a metric that we use to evaluate the performance of the Partnership's storage and terminalling assets. We define storage utilization as the percentage of the contracted capacity in barrels compared to the design capacity of the tank.

Operating Expenses and Total Maintenance Spend

Operating Expenses

Management seeks to maximize profitability by effectively managing operating expenses. These expenses are comprised primarily of labor expenses (including contractor services), general materials, supplies, minor maintenance, utility costs (including electricity and fuel) and insurance premiums. Utility costs fluctuate based on throughput volumes and the grades of crude oil and types of refined products we handle. Other operating expenses generally remain relatively stable across broad ranges of throughput volumes, but can fluctuate from period to period depending on the mix of activities performed during that period.

Total Maintenance Spend - Wholly Owned Assets

We calculate Total Maintenance Spend as the sum of maintenance expenses and maintenance capital expenditures, excluding any reimbursable maintenance capital expenditures. We track these expenses on a combined basis because it is useful to understanding our total maintenance requirements. Total Maintenance Spend for the years ended December 31, 2020 and 2019, is shown in the table below:

	Years Ended December 31,	
	2020	2019
	(in millions of dollars)	
Wholly Owned Assets		
Maintenance expenses	$ 3.8	$ 1.7
Maintenance capital expenditures	2.1	1.1
Maintenance capital recovery (1)	(1.1)	(0.3)
Total Maintenance Spend - Wholly Owned Assets	$ 4.8	$ 2.5

(1) Relates to the portion of maintenance capital for the Griffith Station Incident reimbursable by insurance.

The Partnership seeks to maximize profitability by effectively managing maintenance expenses, which consist primarily of safety and environmental integrity programs. We seek to manage maintenance expenses on owned and operated pipelines by scheduling maintenance over time to avoid significant variability in maintenance expenses and minimize impact on cash flows, without compromising our commitment to safety and environmental stewardship.

Maintenance expenses represent the costs we incur that do not significantly extend the useful life or increase the expected output of property, plant and equipment. These expenses include pipeline repairs, replacements of immaterial sections of pipelines, inspections, equipment rentals and costs incurred to maintain compliance with existing safety and environmental standards, irrespective of the magnitude of such compliance expenses. Maintenance expenses may vary significantly from period to period because certain expenses are the result of scheduled safety and environmental integrity programs, which occur on a multi-year cycle and require substantial outlays.

Maintenance capital expenditures represent expenditures to sustain operating capacity or operating income over the long term. Examples of maintenance capital expenditures include expenditures made to purchase new or replacement assets or extend the useful life of existing assets. These expenditures includes repairs and replacements of storage tanks, replacements of significant sections of pipelines and improvements to an asset’s safety and environmental standards.

Adjusted EBITDA and Cash Available for Distribution

The Partnership defines Adjusted EBITDA as net income before net interest expense, income taxes, gain or loss from disposition of property, plant and equipment, and depreciation and amortization, plus cash distributed to the Partnership from equity method investments for the applicable period, less income from equity method investments. The Partnership defines Adjusted EBITDA attributable to the Partnership as Adjusted EBITDA less Adjusted EBITDA attributable to non-controlling interests. We present these financial measures because we believe replacing our proportionate share of our equity method investments’ net income with the cash received from such equity method investments more accurately reflects the cash flow from our business, which is meaningful to our investors.

We compute and present cash available for distribution and define it as Adjusted EBITDA attributable to the Partnership less maintenance capital expenditures attributable to the Partnership, net interest paid/received, cash reserves, income taxes paid and net adjustments from volume deficiency payments attributable to the Partnership. Cash available for distribution does not reflect changes in working capital balances.

Adjusted EBITDA and cash available for distribution are non-GAAP supplemental financial measures, which are metrics that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or financing methods;
- ability to generate sufficient cash to support decisions to make distributions to our unitholders;
- ability to incur and service debt and fund capital expenditures; and
- viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

We believe that the presentation of Adjusted EBITDA and cash available for distribution provides useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA and cash available for distribution are net income and net cash provided by operating activities, respectively. Adjusted EBITDA and cash available for distribution should not be considered as an alternative to GAAP net income or net cash provided by operating activities.

Adjusted EBITDA and cash available for distribution 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. You should not consider Adjusted EBITDA or cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDA and cash available for distribution may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing its utility. Please read "*Reconciliation of Non-GAAP Measures*" section below for the reconciliation of net income and cash provided by operating activities to Adjusted EBITDA and cash available for distribution.

Factors Affecting Our Business

Partnership business can be negatively affected by sustained downturns or slow growth in the economy in general and is impacted by shifts in supply and demand dynamics, the mix of services requested by the customers of our pipelines, competition and changes in regulatory requirements affecting our customers' operations. For example, as discussed earlier, in March of 2020, demand for many refined petroleum products declined sharply causing refineries to curtail output. The ultimate magnitude and duration of the COVID-19 pandemic, resulting governmental restrictions on the mobility of consumers and the related impact on crude oil prices and the U.S. and global economy and capital markets is uncertain. We did experience some reduction in volumes on our pipelines throughout 2020, which could continue. The uncertain future impacts of COVID-19 and swift shifts in the demand for oil may negatively impact our financial position, particularly our cash flows and liquidity. As of the date of this Annual Report, all of our assets remain operational.

Changes in Crude Oil and Natural Gas Sourcing and Refined Product and Diluent Demand Dynamics

To effectively manage our business, we monitor our market areas for both short-term and long-term shifts in crude oil, natural gas, refined products and diluent supply and demand. Changes in crude oil and natural gas supply such as new discoveries of reserves, declining production in older fields and the introduction of new sources of crude oil and natural gas supply, investment programs of our shippers to maintain or increase production, along with global supply and demand fundamentals such as the strength of the U.S. dollar, weather conditions and competition among oil producing countries for market share, affect the demand for our services from both producers and consumers. One of the strategic advantages of our crude oil pipeline system is its ability to transport attractively priced crude oil from multiple supply sources. Our crude oil shippers periodically change the relative mix of crude oil grades delivered to the refineries and markets served by our pipelines. While these changes in the sourcing patterns of crude oil transported are reflected in changes in the relative volumes of crude oil by type handled by our pipelines, our crude oil transportation revenue is primarily affected by changes in overall crude oil supply and demand dynamics.

Similarly, our refined products pipeline system has the ability to serve multiple demand centers. Our refined products shippers periodically change the relative mix of refined products shipped on our refined products pipeline system, as well as the destination points, based on changes in pricing and demand dynamics. While these changes in shipping patterns are reflected in relative types of refined products handled by our pipeline, our total product transportation revenue is primarily affected by changes in overall refined products and diluent supply and demand dynamics.

Further, the volumes of crude oil that we transport on our BP2 system and refined products and diluent that we distribute on our River Rouge and Diamondback systems depend substantially on the economics of available crude supply for the Whiting Refinery and the economics for refined products and diluent demand in the markets that the pipelines serve. These economics are affected by numerous factors beyond our control, including apportionment on the Enbridge mainline (which offers all of its capacity on an uncommitted basis). In addition, events such as ongoing maintenance at the Whiting Refinery and apportionment on a third-party pipeline, such as the Enbridge mainline, can cause lower throughput on our BP2 system. Volumes are also affected by maintenance and corridor shutdowns due to tie-ins, among other things.

As these supply and demand dynamics shift, we anticipate that we will continue to actively pursue projects that link new sources of supply to producers and consumers. Similarly, as demand dynamics change, we anticipate that we will create new services or capacity arrangements that meet customer requirements.

Changes in Commodity Prices

We do not engage in the marketing and trading of any commodities. We do not take ownership of crude oil, natural gas, refined products or diluent. As a result, our exposure to commodity price fluctuations is limited to the FLA provisions in our tariffs, which are only applicable to certain of our crude oil pipelines. We also have indirect exposure to commodity price fluctuations to the extent such fluctuations affect the shipping patterns of our customers.

Customers

For more information, refer to Item 1 and 2 - *Business and Properties—Customers*.

Regulation

Interstate common carrier pipelines are subject to regulation by various federal, state and local agencies including the FERC, the Environmental Protection Agency and the Department of Transportation. On June 18, 2020, FERC issued a Notice of Inquiry requesting comments on a proposed oil pipeline index using the PPI-FG plus 0.09% as the index level, and requested comments on whether and how the index should reflect changes to FERC's policies regarding income tax costs and return on equity. On December 17, 2020, in Docket No. RM20-14-000, FERC issued an order establishing a new index level of PPI-FG plus 0.78% for the five-year period commencing July 1, 2021. However, requests for rehearing of the December 2020 order establishing this indexing amount were filed with FERC, and those requests remain pending, with rehearing granted for purposes of extending the time FERC has to review these requests. FERC's final application of its indexing rate methodology for the next five-year term of index rates may impact our revenues associated with any transportation services we may provide pursuant to rates adjusted by the FERC oil pipeline index.

Acquisition Opportunities

The Partnership plans to pursue acquisitions of complementary assets from BP as well as third parties subject to market conditions (including the ongoing effects of COVID-19) and our ability to obtain attractive financing. We may also pursue acquisitions jointly with BP Pipelines. BP Pipelines has granted us a right of first offer with respect to its retained ownership interest in Mardi Gras and all of its interests in midstream pipeline systems and assets related thereto in the contiguous United States and offshore Gulf of Mexico that were owned by BP Pipelines when we were established. Neither BP nor any of its affiliates are under any obligation, however, to sell or offer to sell us additional assets or to pursue acquisitions jointly with us, and we are under no obligation to buy any additional assets from them or to pursue any joint acquisitions with them. We will focus our acquisition strategy on transportation and midstream assets within the crude oil, natural gas and refined products sectors. We believe that we are well positioned to acquire midstream assets from BP, and particularly BP Pipelines, as well as third parties, should such opportunities arise. Identifying and executing acquisitions will be a key part of our strategy. However, if we do not make acquisitions on economically acceptable terms, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our available cash.

Financing

We expect to fund future capital expenditures primarily from external sources, including borrowings under our credit facility and potential future issuances of equity and debt securities.

We intend to make cash distributions to unitholders at a minimum distribution rate of $0.2625 per unit per quarter ($1.05 per unit on an annualized basis). Based on the terms of our cash distribution policy, we expect that we will distribute to unitholders and the general partner, as the holder of IDRs, most of the cash generated by operations.

Griffith Station Incident

On June 13, 2019, a building fire occurred at the Griffith Station on BP2. Management performed an evaluation of the assets and determined that an impairment was required. A charge of $4.4 million for the impairment was recorded under "Impairment and other, net" on our consolidated statements of operations for the year ended December 31, 2019. In addition, we incurred $1.6 million as a response expense for the year ended December 31, 2019. Our assets are insured with a deductible of $1.0 million per incident. We accrued an offsetting insurance receivable of $5.0 million resulting in a net charge of $1.0 million to "Impairment and other, net" for the year ended December 31, 2019. The insurance receivable was recorded as $4.3 million under "Other current assets" and $0.7 million under "Other assets" on our consolidated balance sheet as of December 31, 2019.

During the year ended December 31, 2020, we incurred $0.4 million for response expense and received $2.9 million of insurance proceeds. The proceeds have been recorded under "Proceeds from insurance claims" in our consolidated statements of cash flows for the year ended December 31, 2020, leaving a balance of $2.5 million recorded under "Other current assets" on our consolidated balance sheets as of December 31, 2020, for insurance proceeds expected to be received in 2021. In the event that insurance proceeds exceed the receivable balance, such amounts would be recognized as a gain.

Results of Operations

The following tables and discussion contain a summary of our consolidated results of operations for the years ended December 31, 2020 and 2019.

As mentioned above in Item 7 - COVID-19, during 2020, our results of operations were negatively impacted by the COVID-19 pandemic and multiple weather events in the Gulf of Mexico.

	Years Ended December 31,	
	2020	**2019**
	(in millions of dollars)	
Revenue	$ 128.9	$ 128.5
Costs and expenses		
Operating expenses	19.6	20.0
Maintenance expenses	3.8	1.8
General and administrative	16.9	16.9
Depreciation	2.5	2.6
Impairment and other, net	—	1.0
Property and other taxes	0.7	0.7
Total costs and expenses	43.5	43.0
Operating income	85.4	85.5
Income from equity method investments	110.8	116.7
Interest expense, net	7.9	15.1
Net income	188.3	187.1
Less: Net income attributable to non-controlling interests	19.9	19.2
Net income attributable to the Partnership	$ 168.4	$ 167.9
Adjusted EBITDA(1)	$ 213.2	$ 219.5
Less: Adjusted EBITDA attributable to non-controlling interests	24.3	23.2
Adjusted EBITDA attributable to the Partnership(1)	$ 188.9	$ 196.3

(1) See Reconciliations of Non-GAAP Measures below.

Pipeline throughput (thousands of barrels per day)[1]	Years Ended December 31, 2020	2019
BP2	276	300
Diamondback	63	63
River Rouge	69	73
Total Wholly Owned Assets	408	436
Mars	490	546
Caesar	161	194
Cleopatra[2]	18	24
Proteus	214	175
Endymion	214	175
Mardi Gras Joint Ventures	607	568
Ursa	78	107
Average revenue per barrel ($ per barrel)[3]		
Total Wholly Owned Assets	$ 0.77	$ 0.77
Mars	1.35	1.31
Mardi Gras Joint Ventures	0.59	0.65
Ursa	0.90	0.87

(1) Pipeline throughput is defined as the volume of delivered barrels.

(2) Natural gas is converted to oil equivalent at 5.8 million cubic feet per one thousand barrels.

(3) Based on reported revenues from transportation and allowance oil divided by delivered barrels over the same period.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Total revenue increased by $0.4 million, or 0.3%, in the year ended December 31, 2020, compared to the year ended December 31, 2019, primarily due to the following:

- Increase of $7.6 million or 136.6% in deficiency revenue from our throughput and deficiency agreements with BP.
- Decrease of $4.5 million or 43.5% in FLA revenue from BP2 driven by a decrease in in throughput volume and a decrease in FLA prices realized.
- Decrease of $2.7 million in tariff revenue driven by a decrease of $3.1 million on BP2, a $0.5 million increase on Diamondback and a $0.1 million decrease on River Rouge.
- Throughput volume decreased by 9.3 million barrels primarily driven by a 8.4 million decrease on BP2, a 0.3 million increase on Diamondback and a 1.2 million decrease on River Rouge.

Operating expenses decreased by $0.4 million, or 2.0%, in the year ended December 31, 2020, compared to the year ended December 31, 2019, primarily due to decrease in variable expense due to lower throughput volumes.

Maintenance expenses increased by $2.0 million, or 111.1%, in the year ended December 31, 2020, compared to the year ended December 31, 2019, primarily as a result of an increase from inspection costs and corrosion projects on River Rouge.

General and administrative expenses was flat in the year ended December 31, 2020, compared to the year ended December 31, 2019.

Impairment expense decreased by $1.0 million in the year ended December 31, 2020 compared to the year ended December 31, 2019 due to no impairment charge taken.

Income from equity method investments decreased by $5.9 million, or 5.1%, in the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to lower earnings from Mars and Ursa driven by lower throughput volume, unplanned maintenance and producer shut-ins from hurricanes. Earnings from KM Phoenix were lower in the year ended December 31, 2020 compared to year ended December 31, 2019.

Interest expense, net was $7.9 million in the year ended December 31, 2020 compared to $15.1 million in the year ended December 31, 2019 due to lower interest rates tied to LIBOR.

Reconciliation of Non-GAAP Measures

The following tables present a reconciliation of Adjusted EBITDA to net income and to net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated.

	Years Ended December 31,	
	2020	2019
	(in millions of dollars)	
Reconciliation of Adjusted EBITDA and Cash Available for Distribution to Net Income		
Net income	$ 188.3	$ 187.1
Add:		
Depreciation	2.5	2.6
Interest expense, net	7.9	15.1
Cash distributions received from equity method investments	125.3	131.4
Less:		
Income from equity method investments	110.8	116.7
Adjusted EBITDA	213.2	219.5
Less:		
Adjusted EBITDA attributable to non-controlling interests	24.3	23.2
Adjusted EBITDA attributable to the Partnership	188.9	196.3
Add:		
Maintenance capital recovery[(1)]	1.1	0.3
Less:		
Net interest paid/(received)	11.3	15.1
Maintenance capital expenditures	2.1	1.1
Cash reserves[(2)]	(3.0)	—
Cash available for distribution attributable to the Partnership	$ 179.6	$ 180.4

(1) Relates to the portion of maintenance capital for the Griffith Station Incident reimbursable by insurance.
(2) Reflects cash reserved due to timing of interest payment(s).

	Years Ended December 31,	
	2020	2019
	(in millions of dollars)	
Reconciliation of Adjusted EBITDA and Cash Available for Distribution to Net Cash Provided by Operating Activities		
Net cash provided by operating activities	$ 190.4	$ 189.3
Add:		
Interest expense, net	7.9	15.1
Distribution in excess of earnings from equity method investments	13.0	11.5
Less:		
Change in other assets and liabilities	(2.1)	(4.9)
Non-cash adjustments	0.2	0.3
Impairment and other, net(1)	—	1.0
Adjusted EBITDA	213.2	219.5
Less:		
Adjusted EBITDA attributable to non-controlling interests	24.3	23.2
Adjusted EBITDA attributable to the Partnership	188.9	196.3
Add		
Maintenance capital recovery(2)	1.1	0.3
Less:		
Net interest paid/(received)	11.3	15.1
Maintenance capital expenditures	2.1	1.1
Cash reserves(3)	(3.0)	—
Cash available for distribution attributable to the Partnership	$ 179.6	$ 180.4

(1) This includes $6.0 million of costs related to the Griffith Station Incident (impairment charge of $4.4 million and $1.6 million as a response expense), net of $5.0 million in offsetting insurance receivable. The net charge of $1.0 million reflects our insurance deductible.
(2) Relates to the portion of maintenance capital for the Griffith Station Incident reimbursable by insurance.
(3) Reflects cash reserved due to timing of interest payment(s).

Capital Resources and Liquidity

Currently, we expect our primary ongoing sources of liquidity to be cash generated from operations (including distribution from our equity method investments), and, as needed, borrowings under our existing credit facility. The entities in which we own an interest may also incur debt. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements and to make quarterly cash distributions.

Based upon current expectations for the fiscal year 2021, we believe that our cash on hand, cash flow from operations and borrowings available under our credit facility will be sufficient to fund our operations for 2021. As of December 31, 2020, our liquidity was $258.9 million, consisting of $126.9 million of cash and $132 million available under our existing credit facility with BP. Our only debt outstanding is our $468 million borrowed under our term loan with an affiliate of BP, and there are no principal payments required with respect to that facility until 2025.

During 2020, our results of operations were negatively impacted by the COVID-19 pandemic and multiple weather events in the Gulf of Mexico. The MVC agreements executed on November 3, 2020 provide downside protection to the Partnership albeit at a lower level than in prior years on BP2 and Diamondback. Additionally, there is risk of decreased volumes with respect to the offshore operations if operators take actions to reduce operations in response to demand declines or increasingly limited storage availability or are unable to control COVID-19 infections on platforms and are required to shut-in. In the longer term, if reduced demand were to persist through 2021 or longer, we may not be able to continue to generate similar levels of operating cash flow and our liquidity and capital resources may not be sufficient to make our current levels of cash distributions to unitholders or even meet our minimum quarterly distribution. Although we continue to actively work to mitigate the evolving challenges and growing impact of both the COVID-19 pandemic and the industry downturn on our operations and our financial condition, there is no certainty that the measures we take will be ultimately sufficient.

Cash Distributions

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we intend to pay a minimum quarterly distribution of $0.2625 per unit per quarter, which equates to approximately $27.5 million per quarter, or $110.0 million per year in the aggregate, based on the number of common and subordinated units outstanding as of December 31, 2020. We intend to pay such distributions to the extent we have sufficient cash after the establishment of cash reserves and the payment of expenses, including payments to our general partner and its affiliates.

Revolving Credit Facility

On October 30, 2017, the Partnership entered into a $600.0 million unsecured revolving credit facility agreement with an affiliate of BP. The credit facility terminates on October 30, 2022 and provides for certain covenants, including the requirement to maintain a consolidated leverage ratio, which is calculated as total indebtedness to consolidated EBITDA (as defined in the credit facility), not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. In addition, the limited liability company agreement of our general partner requires the approval of BP Holdco prior to the incurrence of any indebtedness that would cause our leverage ratio to exceed 4.5 to 1.0.

The credit facility also contains customary events of default, such as (i) nonpayment of principal when due, (ii) nonpayment of interest, fees or other amounts, (iii) breach of covenants, (iv) misrepresentation, (v) cross-payment default and cross-acceleration (in each case, to indebtedness in excess of $75.0 million) and (vi) insolvency. Additionally, the credit facility limits our ability to, among other things: (i) incur or guarantee additional debt, (ii) redeem or repurchase units or make distributions under certain circumstances; and (iii) incur certain liens or permit them to exist. Indebtedness under this facility bears interest at the 3-month London Interbank Offered Rate ("LIBOR") plus 0.85%. This facility includes customary fees, including a commitment fee of 0.10% and a utilization fee of 0.20%.

In connection with our acquisition in the fourth quarter of 2018, we borrowed $468.0 million from the credit facility. This amount was outstanding at December 31, 2019, and repaid on March 13, 2020.

Term Loan Facility Agreement

On February 24, 2020, the Partnership entered into a $468.0 million Term Loan Facility Agreement ("term loan") with an affiliate of BP. On March 13, 2020, proceeds were used to repay outstanding borrowings under the existing credit facility. The term loan has a final repayment date of February 24, 2025, and provides for certain covenants, including the requirement to maintain a consolidated leverage ratio, which is calculated as total indebtedness to consolidated EBITDA, not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. Simultaneous with this transaction, we entered into a First Amendment to Short Term Credit Facility Agreement ("First Amendment") whereby the lender added a provision that indebtedness under both the term loan and credit facility shall not exceed $600.0 million. All other terms of the credit facility remain the same. As of December 31, 2020, the Partnership was in compliance with the covenants contained in the credit facility and term loan.

Cash Flows from Our Operations

Operating Activities. We generated $190.4 million in cash flow from operating activities in the year ended December 31, 2020, compared to the $189.3 million generated in the year ended December 31, 2019. The $1.1 million increase in cash flows from operations primarily resulted from a decrease in interest expense, offset by a decrease in distribution of earnings from equity method investments.

***Investing Activities*.** Our cash flows from investing activities were $12.4 million in the year ended December 31, 2020, compared to $10.4 million in the year ended December 31, 2019. The $2.0 million increase in cash inflows from investing activities is primarily due to an increase of $1.5 million distribution in excess of earnings from equity method investments, and an increase of $2.9 million from proceeds from insurance claims related to Griffith Station incident, partially offset by an increase of $2.4 million in funds used for capital expenditures.

***Financing Activities*.** Our cash flows used in financing activities were $174.7 million in the year ended December 31, 2020 and $157.9 million in the year ended December 31, 2019. The $16.8 million increase in cash outflows used in financing activities is primarily due to distributions to unitholders and general partner and non-controlling interests.

Capital Expenditures

Our operations can be capital intensive, requiring investment to expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements consist of maintenance capital expenditures and expansion capital expenditures, both as defined in our partnership agreement. We are required to distinguish between maintenance capital expenditures and expansion capital expenditures in accordance with our Partnership agreement.

A summary of capital expenditures associated with ongoing projects related to the Wholly Owned Assets, for the years ended December 31, 2020 and 2019, is shown in the table below:

	Years Ended December 31,	
	2020	2019
	(in millions of dollars)	
Cash spent on expansion capital expenditures	$ 1.4	$ —
Cash spent on maintenance capital expenditures	2.1	1.1
Increase in accrued capital expenditures	3.9	—
Increase in capital expenditures reimbursable to our Parent	0.3	—
Total capital expenditures incurred	$ 7.7	$ 1.1

In the year 2020, we incurred $4.1 expansion capital expenditures for an onshore capacity increase project and $3.6 maintenance capital expenditures primarily associated with the following projects:

- BP2 motor purchase and installation;
- Griffith Station recovery, including a building, lighting, power, relay and PLC panels.

In the year 2019, we incurred $1.1 million maintenance capital expenditures, associated with the following projects:

- Projects to support critical equipment reliability for River Rouge;
- Densitometer installations at South Bend, Jackson, Dearborn, Buckeye Detroit and River Rouge; and
- Griffith Station recovery, including a building, lighting, power, relay and PLC panels.

We anticipate that our 2021 capital expenditures will be funded with cash from operations and borrowings under our credit facility.

Contractual Obligations

A summary of our contractual obligations at December 31, 2020, is shown in the table below:

(in millions of dollars)	Total	Less than 1 year	Years 2 to 3	Years 4 to 5	More than 5 years
Term Loan Facility(1)	$ 486.7	$ 4.5	$ 9.0	$ 473.2	$ —
Credit Facility(2)	0.2	0.1	0.1	—	—
Rights-of-way	3.1	0.1	0.2	0.2	2.6
Operating leases	0.7	0.1	0.1	0.1	0.4
Total	$ 490.7	$ 4.8	$ 9.4	$ 473.5	$ 3.0

(1) Includes principal and interest expense, based on the current interest rate. Refer to Note 9 - *Debt* in the Notes to Consolidated Financial Statements.
(2) Includes commitment fee on available facility. Refer to Note 9 - *Debt* in the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements

The Partnership has not entered into any transactions, agreements or other contractual arrangements that would result in off-balance sheet liabilities.

Critical Accounting Policies and Estimates

Critical accounting policies are those that are important to our financial condition and require management's most difficult, subjective or complex judgments. Different amounts would be reported under different operating conditions or under alternative assumptions. We have evaluated the accounting policies used in the preparation of the consolidated financial statements of the Partnership and related notes thereto and believe those policies are reasonable and appropriate.

We apply those accounting policies that we believe best reflect the underlying business and economic events, consistent with GAAP. Our more critical accounting policies include those related to revenue recognition and common control transactions. Inherent in such policies are certain key assumptions and estimates. We periodically update the estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. Our significant accounting policies are summarized in Note 2 - *Summary of Significant Accounting Policies* in the Notes to Consolidated Financial Statements. We believe the following to be our most critical accounting policies applied in the preparation of our financial statements.

Accounting for Equity Method Investments

The Partnership maintains investments in several joint ventures that are accounted for under the equity method of accounting. Under the equity method of accounting, investments are recorded at historical cost as an asset and adjusted for capital contributions, dividends received, and the Partnership's share of the investees' earnings or losses, which is recorded as a component of income from equity method investments. As of December 31, 2020, the Partnership's equity method investments balance was $519.9 million, and for the year ended December 31, 2020, the Partnership's income from equity method investments was $110.8 million.

The Partnership does not have a controlling interest in our investments in joint ventures; however, because of the significance of the investments to our financial statements our management exercises critical judgments when assessing the results of the joint ventures' operations and the accounting judgments made by the operators. This requires management to rely on their experience in the industry and their knowledge of the joint ventures involved in making final assessments on the recognition of operating results as reported to the Partnership by the operators.

The Partnership assesses its equity method investments for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred. When the loss is deemed to be other-than-temporary, the carrying value of the equity method investment is written down to fair value. For the years December 31, 2020 and 2019, there were no indicators of an other-than-temporary impairment identified.

Revenue Recognition

Our revenues are primarily generated from crude oil, refined products and diluent transportation services. We recognize revenue over time or at a point in time, depending on the nature of the performance obligations contained in the respective contract with customers. A performance obligation is our unit of account and it represents a promise in a contract to transfer goods or services to the customer. The contract transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is allocated to each performance obligation and recognized as revenue when or as the performance obligation is satisfied.

We entered into multiple long-term fee-based transportation agreements with BP Products, an indirect wholly owned subsidiary of BP. Under these agreements, BP Products has committed to pay us the minimum volumes at the applicable rates for each of the twelve-month measurement periods specified by the applicable agreements whether or not such volumes are physically transported through our pipelines. BP Products is allowed to make up for shortfall volumes during each of the measurement periods.

Contracts with BP Products, including the allowance oil arrangements discussed below, are accounted for as separate arrangements because they do not meet the criteria for combination. We record revenue for crude oil, refined products and diluent transportation over the period in which they are earned (i.e., either physical delivery of product has taken place, or the services designated in the contract have been performed). Revenue from transportation services is recognized upon delivery or receipt based on contractual rates related to throughput volumes. We accrue revenue based on services rendered but not billed for that accounting month.

Billings to BP Products for deficiency volumes under its minimum volume commitments, if any, are recorded in deferred revenue and credits on our consolidated balance sheets, as BP Products has the right to make up the deficiency volumes within the measurement period specified by the agreements. We consider this deferred revenue as breakage revenue and considered three methods of determining when or if to recognize the amounts into revenue. We recognize the breakage amount as revenue when the likelihood of the customer exercising its remaining rights becomes remote.

The unfulfilled obligations in our revenue contracts are our obligations to transport certain volumes of crude or diluent molecules (throughput) for our customers throughout the term of each contract. The terms of the contract require the customer to deliver a specified quantity of molecules or minimum volume each day with a right to make up any short fall within the 12 month measurement period of each contract. At the end of each quarterly reporting period we analyze the customer's actual shipments compared to their minimum volume commitments to measure the level of fulfillment toward the contracted minimum volume commitments. This analysis also includes the review of the capacity of each pipeline available for the customer to deliver the required volume to make up for any shortfall, current forecast of the customers' future shipments, an assessment of whether management thinks the customers can make up for the shortfall and any impact market conditions have on the probability of customers making up the shortfall. If our assessment concludes that it is remote that the customer will make up for volume shortfalls and require performance of the unfulfilled obligations, the appropriate level of breakage is recognized into revenue.

Common Control Transactions

Assets and businesses acquired from our Parent and its subsidiaries are accounted for as common control transactions whereby the net assets acquired are included in our consolidated balance sheets at their historical carrying value. BP maintains its accounting records in accordance with International Financial Reporting Standards, ("IFRS"), and therefore, the determination of historical carrying cost of BP's investment in assets under accounting principles generally accepted in the United States of America, ("US GAAP") required management to make judgments, including assessing the impact of the joint venture formation transaction under US GAAP and its impact on the carrying value of the asset in the financial statements.

If any recognized consideration transferred in such a transaction exceeds the historical carrying value of the net assets acquired, the excess is treated as a capital distribution to our Parent, similar to a dividend. If the historical carrying value of the net assets acquired exceeds any recognized consideration transferred including, if applicable, the fair value of any limited partner units issued, such excess is treated as a capital contribution from our Parent.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Since we do not take ownership of the crude oil, natural gas, and refined products or diluent that we transport for our customers, and we do not engage in the marketing and trading of any commodities, we have limited direct exposure to inventory risks associated with fluctuating commodity prices.

Our tariffs for crude oil shipments include an FLA. We do not take physical possession of the allowance oil as a result of our services, but record the volumes accumulated as a receivable from the customer in the month we provide the transportation services. We consider the FLA as a part of the transportation revenue we receive from the customer.

Allowance oil income is subject to more volatility than transportation revenue, as it is directly dependent on commodity prices. As a result, the income we realize under our FLA provisions will increase or decrease as a result of changes in underlying commodity prices. A $5 per barrel change in each applicable commodity price would have changed revenue by approximately $1.0 million for the year ended December 31, 2020. We do not intend to enter into any hedging agreements to mitigate our exposure to decreases in commodity prices through our FLA.

Interest Rate Risk

Our net income is affected by fluctuations in interest rates (e.g. interest expense on variable rate debt). A hypothetical increase of 100 basis points in the interest rate of our debt would impact the Partnership's annual interest expense by approximately $4.7 million, assuming the $468.0 million is outstanding for an entire year.

As announced in July 2017, LIBOR is expected to be phased out by the end of 2021. Uncertainty as to the nature of alternative reference rates and as to potential changes or other reforms to LIBOR may adversely impact our interest rates and related interest expense.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

BP MIDSTREAM PARTNERS LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of BP Midstream Partners GP LLC and
the Partners of BP Midstream Partners LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of BP Midstream Partners LP and subsidiaries (the "Partnership") as of December 31, 2020 and 2019, the related consolidated statements of operations, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2020, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting and our report dated February 25, 2021 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for Equity Method Investments — Refer to Notes 2 and 6 to the financial statements.

Critical Audit Matter Description

The Partnership maintains investments in several joint ventures that are accounted for under the equity method of accounting. Under the equity method of accounting, investments are recorded at historical cost as an asset and adjusted for capital contributions, dividends received, and the Partnership’s share of the investee’s earnings or losses, which is recorded as a component of income from equity method investments. As of December 31, 2020, the Partnership’s equity method investments balance was $519.9 million, and for the year ended December 31, 2020, the Partnership’s income from equity method investments was $110.8 million.

We identified the accounting for equity method investments as a critical audit matter because of the significance of the equity method investments to the Partnership's financial statements, and the judgments made by management when assessing the results of the joint ventures' operations and accounting judgments made by the operator of the equity method investments. This required an increased extent of effort, including the need to involve auditors of the joint ventures and senior members of the engagement team.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the accounting for equity method investments that we concluded were significant components included the following, among others:

- We tested the effectiveness of controls related to the accounting for the Partnership's significant equity method investments, which includes management's attendance at joint venture board meetings and their receipt and review of the equity method investment financial statements.

- We evaluated significant equity method investments and income from equity method investments by:

  – Testing transactions occurring related to the equity method investments, such as purchases or sales of additional interests and distributions.

  – Testing management's assertions that there were no indicators of other-than-temporary impairment of the equity method investments.

  – Evaluating significant judgments and estimates at the underlying equity method investments (including consideration of the impacts of the global coronavirus disease [COVID-19] pandemic and resulting impact on the oil and gas industry) through oversight of the auditors of the equity method investees and by having direct discussions with the accounting function of the equity method investees' management.

  – Evaluating the completeness and accuracy of the Partnership's investment in equity method investments and income from equity method investments by obtaining audited financial statements of the joint ventures.

  – Obtaining, reviewing, and retaining information from the auditors of the joint ventures, such as information necessary to understand significant findings or issues identified by such auditors and actions taken to address them and sufficient information to reconcile the financial statement amounts audited by such auditors to the information underlying the Partnership's financial statements.

  – Performing procedures to evaluate subsequent events impacting the equity method investments prior to the date of our auditor's report on the Partnership's financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2021

We have served as the Partnership's auditor since 2018.

BP MIDSTREAM PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2020	December 31, 2019
	(in millions of dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 126.9	$ 98.8
Accounts receivable – third parties	0.2	0.6
Accounts receivable – related parties	11.0	11.3
Prepaid expenses	6.6	5.1
Other current assets	2.9	5.0
Total current assets	147.6	120.8
Equity method investments (Note 6)	519.9	534.4
Property, plant and equipment, net (Note 7)	67.9	62.7
Other assets	3.5	4.2
Total assets	$ 738.9	$ 722.1
LIABILITIES		
Current liabilities		
Accounts payable – third parties	$ 1.9	$ 0.6
Accounts payable – related parties	1.9	1.7
Deferred revenues and credits – related parties	1.8	1.5
Other current liabilities (Note 8)	7.8	6.6
Total current liabilities	13.4	10.4
Long-term debt – related parties (Note 9)	468.0	468.0
Other liabilities	3.5	3.5
Total liabilities	484.9	481.9
Commitments and contingencies (Note 13)		
EQUITY		
Common unitholders – public (2020 – 47,821,790 units issued and outstanding; 2019 – 47,806,563 units issued and outstanding)	860.1	851.6
Common unitholders – BP Holdco (2020 and 2019 – 4,581,177 units issued and outstanding)	(59.6)	(60.3)
Subordinated unitholders – BP Holdco (2020 and 2019 – 52,375,535 units issued and outstanding)	(680.2)	(689.2)
General partner	1.2	1.2
Total partners' capital	121.5	103.3
Non-controlling interests	132.5	136.9
Total equity	254.0	240.2
Total liabilities and equity	$ 738.9	$ 722.1

The accompanying notes are an integral part of the consolidated financial statements.

BP MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2020	2019	2018
	(in millions of dollars, unless otherwise indicated)		
Revenue			
Third parties	$ 2.9	$ 3.0	$ 2.8
Related parties	126.0	125.5	113.6
Total revenue	128.9	128.5	116.4
Costs and expenses			
Operating expenses – third parties	14.3	14.2	11.5
Operating expenses – related parties	5.3	5.8	5.0
Maintenance expenses – third parties	3.4	1.5	2.6
Maintenance expenses – related parties	0.4	0.3	0.1
General and administrative – third parties	2.4	2.8	4.6
General and administrative – related parties	14.5	14.1	14.1
Depreciation	2.5	2.6	2.7
Impairment and other, net	—	1.0	—
Property and other taxes	0.7	0.7	0.5
Total costs and expenses	43.5	43.0	41.1
Operating income	85.4	85.5	75.3
Income from equity method investments	110.8	116.7	94.4
Interest expense, net	7.9	15.1	4.0
Net income	188.3	187.1	165.7
Less: Net income attributable to non-controlling interests	19.9	19.2	32.6
Net income attributable to the Partnership	$ 168.4	$ 167.9	$ 133.1
Net income attributable to the Partnership per limited partner unit – basic and diluted (in dollars):			
Common units	$ 1.56	$ 1.58	$ 1.27
Subordinated units	$ 1.56	$ 1.58	$ 1.27
Weighted Average Number of Limited Partner Units Outstanding - Basic and Diluted (in millions):			
Common units – public	47.8	47.8	47.8
Common units – BP Holdco	4.6	4.6	4.6
Subordinated units – BP Holdco	52.4	52.4	52.4

The accompanying notes are an integral part of the consolidated financial statements.

BP MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of dollars)	Partners' Capital: Common Unitholders – Public	Partners' Capital: Common Unitholders – BP Holdco	Partners' Capital: Subordinated Unitholders – BP Holdco	Partners' Capital: General Partner	Non-controlling Interests	Total
Balance at December 31, 2017	$ 824.6	$ (47.2)	$ (538.9)	$ —	$ 342.3	$ 580.8
Cumulative effect of accounting change in equity method investments (Note 6)	(1.3)	(0.1)	(1.4)	—	—	(2.8)
Net income	60.7	5.9	66.5	—	32.6	165.7
Distribution to unitholders ($1.0113 per unit) and general partner	(48.3)	(4.7)	(52.9)	—	—	(105.9)
Acquisitions from Parent	0.9	(15.6)	(178.5)	—	(187.6)	(380.8)
Unit-based compensation	0.2	—	—	—	—	0.2
Distributions to non-controlling interests	—	—	—	—	(46.4)	(46.4)
Balance at December 31, 2018	$ 836.8	$ (61.7)	$ (705.2)	$ —	$ 140.9	$ 210.8
Net income	75.5	7.2	82.7	2.5	19.2	187.1
Distribution to unitholders ($1.2733 per unit) and general partner	(60.9)	(5.8)	(66.7)	(1.3)	—	(134.7)
Unit-based compensation	0.2	—	—	—	—	0.2
Distributions to non-controlling interest	—	—	—	—	(23.2)	(23.2)
Balance at December 31, 2019	$ 851.6	$ (60.3)	$ (689.2)	$ 1.2	$ 136.9	$ 240.2
Net income	74.7	7.1	81.8	4.8	19.9	188.3
Distribution to unitholders ($1.3900 per unit) and general partner	(66.4)	(6.4)	(72.8)	(4.8)	—	(150.4)
Unit-based compensation	0.2	—	—	—	—	0.2
Distributions to non-controlling interest	—	—	—	—	(24.3)	(24.3)
Balance at December 31, 2020	$ 860.1	$ (59.6)	$ (680.2)	$ 1.2	$ 132.5	$ 254.0

The accompanying notes are an integral part of the consolidated financial statements.

BP MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2020	2019	2018
Cash flows from operating activities	(in millions of dollars)		
Net income	$ 188.3	$ 187.1	$ 165.7
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation	2.5	2.6	2.7
Impairment and other, net	—	1.0	—
Non-cash expenses	0.2	0.3	0.2
Income from equity method investments	(110.8)	(116.7)	(94.4)
Distributions of earnings received from equity method investments	112.3	119.9	98.1
Changes in operating assets and liabilities			
Accounts receivable	0.7	(1.8)	(0.4)
Prepaid expenses and other current assets	(1.4)	(0.5)	(3.3)
Accounts payable	0.9	(2.4)	0.8
Deferred revenues and credits – related parties	0.3	0.4	1.1
Other	(2.6)	(0.6)	3.3
Net cash provided by operating activities	190.4	189.3	173.8
Cash flows from investing activities			
Capital expenditures	(3.5)	(1.1)	(1.6)
Proceeds from insurance claims	2.9	—	—
Acquisitions from Parent	—	—	(87.2)
Distribution in excess of earnings from equity method investments	13.0	11.5	19.6
Net cash provided by (used in) investing activities	12.4	10.4	(69.2)
Cash flows from financing activities			
Proceeds from issuance of debt – related parties	468.0	—	468.0
Repayment of debt – related parties	(468.0)	—	(15.0)
Distribution of IPO proceeds to our Parent	—	—	(0.2)
Acquisitions from Parent	—	—	(380.8)
Distributions to unitholders and general partner	(150.4)	(134.7)	(105.9)
Distributions to non-controlling interests	(24.3)	(23.2)	(46.4)
Net cash used in financing activities	(174.7)	(157.9)	(80.3)
Net change in cash and cash equivalents	28.1	41.8	24.3
Cash and cash equivalents at beginning of the year	98.8	57.0	32.7
Cash and cash equivalents at end of the year	$ 126.9	$ 98.8	$ 57.0
Supplemental cash flow information			
Cash paid for interest	$ 11.6	$ 16.4	$ 0.7
Cash paid for lease liabilities	0.1	0.1	—
Non-cash investing and financing transactions:			
Accrued capital expenditures	4.1	0.2	0.2

The accompanying notes are an integral part of the consolidated financial statements.

1. Business and Basis of Presentation

BP Midstream Partners LP (either individually or together with its subsidiaries, as the context requires, the “Partnership”) is a Delaware limited partnership formed on May 22, 2017 by BP Pipelines (North America) Inc. (“BP Pipelines”), an indirect wholly owned subsidiary of BP p.l.c. (“BP”), a “foreign private issuer” within the meaning of the Securities Exchange Act of 1934, as amended. On October 30, 2017, the Partnership completed its initial public offering (the "IPO") of common units representing limited partner interests.

Unless otherwise stated or the context otherwise indicates, all references to “we,” “our,” “us,” or similar expressions refer to the legal entity BP Midstream Partners LP. The term “our Parent” refers to BP Pipelines; any entity that wholly owns BP Pipelines, indirectly or directly, including BP and BP America Inc. (“BPA”), an indirect wholly owned subsidiary of BP; and any entity that is wholly owned by the aforementioned entities, excluding BP Midstream Partners LP.

Business

BP Midstream Partners LP is a master limited partnership formed by BP Pipelines to own, operate, develop and acquire pipelines and other midstream assets. The Partnership's assets consist of interests in entities that own crude oil, natural gas, refined products and diluent pipelines and refined product terminals serving as key infrastructure for BP and other customers to transport onshore crude oil production to BP’s refinery in Whiting, Indiana (the "Whiting Refinery") and offshore crude oil and natural gas production to key refining markets and trading and distribution hubs. Certain assets deliver refined products and diluent from the Whiting Refinery and other U.S. supply hubs to major demand centers.

As of December 31, 2020, the Partnership's assets consisted of the following:

- BP Two Pipeline Company LLC, which owns the BP#2 crude oil pipeline system (“BP2”).
- BP River Rouge Pipeline Company LLC, which owns the Whiting to River Rouge refined products pipeline system (“River Rouge”).
- BP D-B Pipeline Company LLC, which owns the Diamondback diluent pipeline system (“Diamondback”). BP2, River Rouge, and Diamondback, together, are referred to as the "Wholly Owned Assets".
- 28.5% ownership interest in Mars Oil Pipeline Company, LLC (“Mars”), which owns a major corridor crude oil pipeline system in the Gulf of Mexico.
- 65% ownership interest and 100% managing member interest in Mardi Gras Transportation System Company, LLC (“Mardi Gras”), which holds the following investments in joint ventures located in the Gulf of Mexico:
    - 56% ownership interest in Caesar Oil Pipeline Company, LLC (“Caesar”),
    - 53% ownership interest in Cleopatra Gas Gathering Company, LLC (“Cleopatra”),
    - 65% ownership interest in Proteus Oil Pipeline Company, LLC (“Proteus”), and,
    - 65% ownership interest in Endymion Oil Pipeline Company, LLC (“Endymion”).
    - Together Endymion, Caesar, Cleopatra and Proteus are referred to as the “Mardi Gras Joint Ventures.”
- 22.7% ownership interest in Ursa Oil Pipeline Company, LLC ("Ursa").
- 25% ownership interest in KM Phoenix Holdings, LLC ("KM Phoenix").

We generate a majority of revenue by charging fees for the transportation of crude oil, refined products and diluent through our pipelines under agreements with minimum volume commitments ("MVC"). We do not engage in the marketing and trading of any commodities. All operations are conducted in the United States, and all long-lived assets are located in the United States. Partnership operations consist of one reportable segment.

Certain Partnership businesses are subject to regulation by various authorities including, but not limited to FERC. Regulatory bodies exercise statutory authority over matters such as common carrier tariffs, construction, rates and ratemaking and agreements with customers.

Basis of Presentation

Consolidated financial statements have been prepared under the rules and regulations of the Securities and Exchange Commission (“SEC”). These rules and regulations conform to the accounting principles contained in the Financial Accounting

Standards Board's ("FASB") Accounting Standards Codification, the single source of accounting principles generally accepted in the United States ("GAAP").

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include all subsidiaries, where the Partnership has control and a variable interest entity ("VIE") of which we are the primary beneficiary. The assets and liabilities in the consolidated financial statements have been reflected on a historical basis. All inter-company accounts and transactions are eliminated upon consolidation.

We evaluate our ownership, contractual arrangements and other interests in entities to determine if these entities are VIEs and whether we are the primary beneficiary of the VIE. In determining whether we are the primary beneficiary of a VIE and therefore required to consolidate the VIE, we apply a qualitative approach that determines whether we have both (1) the power to direct the activities of the VIE that most significantly impact the economic performance and (2) the obligation to absorb the majority of losses of or the rights to receive the majority of the benefits from the VIE that could potentially be significant to the VIE. We continuously assess whether we are the primary beneficiary of a VIE as changes to existing relationships or future transactions may result in the consolidation or deconsolidation, as the case may be, of such VIE.

We consolidate BP2, River Rouge and Diamondback, as we control these entities through 100% of the ownership interest. We control and consolidate Mardi Gras via an agreement between us and our Parent, under which we have the right to vote 100% of Mardi Gras' interests in each of the Mardi Gras Joint Ventures. We have determined that we are the primary beneficiary of Mardi Gras. Refer to Note 16 - *Variable Interest Entity* for further discussion.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported on the consolidated financial statements and disclosures included in the accompanying notes. Actual results could differ from these estimates.

Common Control Transactions

Assets and businesses acquired from our Parent and its subsidiaries are accounted for as common control transactions whereby the net assets acquired are included in our consolidated balance sheets at their historical carrying value. If any recognized consideration transferred in such a transaction exceeds the historical carrying value of the net assets acquired, the excess is treated as a capital distribution to our Parent, similar to a dividend. If the historical carrying value of the net assets acquired exceeds any recognized consideration transferred including, if applicable, the fair value of any limited partner units issued, such excess is treated as a capital contribution from our Parent.

Revenue Recognition

We recognize revenue at an amount that reflects the consideration to which we expect to be entitled in exchange for transferring goods or services to a customer. We include certain disclosures regarding qualitative and quantitative information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. Refer to Note 4 - *Revenue Recognition* for further information.

Equity Method Investments

We account for an investment under the equity method if we have the ability to exercise significant influence, but not control, over the investee. Under the equity method of accounting, the investment is recorded at its initial carrying value on the consolidated balance sheets and is adjusted for capital contributions, dividends received and our share of the investee's earnings or losses, which is recorded as a component of Income from equity method investments on the consolidated statements of operations.

We evaluate equity method investments for impairment when events or changes in circumstances indicate, in our management's judgment, that a decline in value is other than temporary. Factors that may indicate that a decline in value is other than temporary include a deterioration in the financial condition of the investee, decisions to sell the investee, significant losses incurred by the investee, a change in the economic environment that is expected to adversely affect the investee's operations, an investee's loss of a principal customer or supplier and an investee's recording of impairment charges. If we determine that a decline in value is other than temporary, the investment is written down to its fair value, which establishes the investment's new cost basis.

Property, plant and equipment

Our property, plant and equipment is recorded at its historical cost of construction, or the carrying value of the transferring entity in a transaction under common control, or at fair value in a business combination. We record depreciation using the straight-line method with the following useful lives:

	Depreciable Lives (Years)
Land	—
ROW assets	—
Buildings and improvements	16 - 40
Pipelines and equipment	17 - 40
Other	4 - 23
Construction in progress	—

Upon the sale or retirement of property, plant and equipment, the cost and related accumulated depreciation are removed, and any resulting gain or loss is recorded on the consolidated statements of operations.

Ordinary maintenance and repair costs are generally expensed as incurred. Such costs are recorded in Maintenance expenses- third parties and Maintenance expenses-related parties on our consolidated statements of operations. Costs of major renewals, betterments and replacements are capitalized as Property, plant and equipment. For constructed assets, we capitalize all construction-related direct labor and material costs, as well as indirect construction costs.

Impairment of Long-lived Assets

We evaluate long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment, such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying values of an asset group based on the long-lived assets' ability to generate future cash flows on an undiscounted basis. If the carrying amount is higher than the undiscounted cash flows, we further evaluate the impairment loss by comparing management's estimate of the fair value of the assets to the carrying value of such assets. We record a loss for the amount that the carrying value exceeds the estimated fair value.

Cash Equivalents

Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and will mature within 90 days or less from the date of acquisition. We record cash equivalents, if any, at its carrying value, which approximates its fair value.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable represent valid claims against customers for services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Our policy is to establish provisions for losses on accounts receivable due from shippers if we determine that we will not collect all or part of the outstanding balance.

Outstanding customer receivables are regularly reviewed for possible nonpayment indicators, and allowances for doubtful accounts are recorded based upon management's estimate of collectability based on a historical analysis of uncollected amounts, general and specific economic trends, known specific issues related to individual customers, sectors and transactions that might impact collectability at each balance sheet date. At December 31, 2020 and 2019, more than 95% of our accounts receivable are with a related party and we have not experienced any significant collection issues and do not expect collection issues in the foreseeable future; therefore, we have recorded zero in allowance for doubtful accounts.

Income Taxes

BP Midstream Partners LP is treated as a partnership for federal and state income tax purposes, with each partner being separately taxed on its share of taxable income. We are not subject to U.S. federal income taxes. Rather, our taxable income flows through to the owners, who are responsible for paying the applicable income taxes on the income allocated to them. For tax years beginning on or after January 1, 2018, we are subject to partnership audit rules enacted as part of the Bipartisan Budget Act of 2015 (the "Centralized Partnership Audit Regime"). Under the Centralized Partnership Audit Regime, any IRS audit of the Partnership would be conducted at the Partnership level, and if the IRS determines an adjustment, the default rule is that we would pay an "imputed underpayment" including interest and penalties, if applicable. We may instead elect to make a "push-out" election, in which case the partners for the year that is under audit would be required to take into account the adjustments on their own personal income tax returns.

Our partnership agreement does not stipulate how we will address imputed underpayments. If we receive an imputed underpayment, a determination will be made based on the relevant facts and circumstances that exist at that time. We may treat any payments of imputed underpayment, which are made on behalf of our unitholders, as distribution of cash to such unitholders.

Asset Retirement Obligations

Asset retirement obligations represent legal and constructive obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses at fair value on a discounted basis when they are incurred and can be reasonably estimated. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when settled at the time the asset is taken out of service.

Although the Wholly Owned Assets will be replaced as needed, in management's judgement, the pipelines will continue to exist for an indefinite period of time. Therefore, there is uncertainty around the asset retirement settlement dates. As a result, we determined that there is not sufficient information to make a reasonable estimate of the asset retirement obligations for the Wholly Owned Assets, and we did not recognize any asset retirement obligations as of December 31, 2020 and 2019.

We continue to evaluate our asset retirement obligations and future developments that could impact the amounts we record.

Legal

We are subject to litigation and regulatory proceedings as the result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred.

Environmental Matters

We are subject to federal, state, and local environmental laws and regulations. These laws require us to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by us or other parties. Environmental expenditures that are required to obtain future economic benefits from its assets are capitalized as part of those assets. Expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future earnings shall be expensed, unless already provisioned for, which then shall be charged against provisions.

Provisions are recognized when we have a present legal or constructive obligation as a result of a past event, if it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. We do not discount environmental liabilities, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable, and when we can reasonably estimate the costs. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs.

Generally, our recording of these provisions coincides with our commitment to a formal plan of action, or if earlier, on the closure or divestment of inactive sites. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. The ultimate requirement for remediation and its cost are inherently difficult to estimate. We believe that the outcome of these uncertainties should not have a material adverse effect on our financial condition, cash flows, or operating results.

Our existing environmental conditions prior to the IPO are obligations contributed to us by the prior operator of these facilities, BP Pipelines, who has agreed to indemnify us with respect to such conditions under the terms of an omnibus agreement that we entered into in connection with the IPO. For provisions related to such conditions, we record indemnification assets in our consolidated balance sheets in the amounts that equal the provisions. Subsequent to the IPO, revisions to the estimated environmental liability for conditions that are not indemnified under the omnibus agreement with our Parent are reflected in our consolidated statements of operations when they are probable and reasonably estimable.

For additional information regarding our environmental matters, refer to Note 13 - *Commitments and Contingencies*.

Other Contingencies

We recognize liabilities for contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the lower end of the range is accrued. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected.

Fair Value Estimates

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. We categorize assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement:

- Level 1 inputs are quoted prices in active markets for identical assets or liabilities.
- Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability.
- Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

We classify the fair value of an asset or liability based on the lowest level of input significant to its measurement. A fair value initially reported as Level 3 will be subsequently reported as Level 2 if the unobservable inputs become inconsequential to its measurement, or corroborating market data becomes available. Asset and liability fair values initially reported as Level 2 will be subsequently reported as Level 3 if corroborating market data becomes unavailable.

Net Income per Unit

Net income per unit applicable to common limited partner units and to subordinated limited partner units is computed by dividing the respective limited partners' interest in net income by the weighted average number of common units and subordinated units, respectively, outstanding for the period. Because we have more than one class of participating securities, we use the two-class method when calculating the net income per unit applicable to limited partners. The classes of participating securities include common units, subordinated units and incentive distribution rights.

Unit-Based Compensation

The fair value of phantom unit awards granted to non-employee directors is based on the fair market value of our common units on the date of grant. Our unit-based compensation expenses are recognized ratably over the vesting term of the awards. We have elected to recognize the impact of forfeitures only when they occur.

Leases

We recognize an operating lease right-of-use (“ROU”) asset and a corresponding operating lease liability on our consolidated balance sheets based on the present value of the future minimum lease payments over the lease term at commencement date for arrangements with duration greater than one year. We use our incremental borrowing rate to determine the present value of future minimum lease payments over the duration of the lease term, which is determined to be reasonably certain. We do not separate lease and non-lease components for accounting purposes.

3. Acquisitions

Acquisition of Equity Interests

On October 1, 2018, pursuant to an Interest Purchase Agreement (the “Interest Purchase Agreement”) with BP Products North America Inc. (“BP Products”), BP Offshore Pipelines Company LLC (“BP Offshore”), and BP Pipelines completed the acquisition of:

- (i) an additional 45.0% interest in Mardi Gras, from BP Pipelines, which brought our ownership interest to 65.0%,
- (ii) a 22.7% interest in Ursa, from BP Offshore, and
- (iii) a 25% interest in KM Phoenix, from BP Products.

These assets were acquired in exchange for aggregate consideration of $468.0 million funded with borrowings under our revolving credit facility. The purchase was accounted for as an acquisition of assets between entities under common control; as a result, we recognized the acquired assets at their historical carrying value. The consideration paid is reported in our consolidated statements of cash flows as $380.8 million in financing activities for the distributions to our Parent for the acquisition of the non-controlling interest in Mardi Gras and excess of the purchase price over the carrying value for other assets acquired and $87.2 million in investing activities for the remainder. For more details, refer to the consolidated statements of cash flows.

4. Revenue Recognition

We recognize revenue over time or at a point in time, depending on the nature of the performance obligations contained in the respective contract with customers. A performance obligation is our unit of account and it represents a promise in a contract to transfer goods or services to the customer. The contract transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is allocated to each performance obligation and recognized as revenue when or as the performance obligation is satisfied. The following is an overview of our significant revenue stream, including a description of the respective performance obligations and related methods of revenue recognition.

Pipeline Transportation

Revenue from pipeline transportation is comprised of tariffs and fees associated with the transportation of liquid petroleum products, generally at published tariffs and in certain instances, revenue from MVC contracts at negotiated rates. Tariff revenue is recognized either at the point of delivery or at the point of receipt, pursuant to specifications outlined in the respective tariffs. We record revenue for crude oil, refined products and diluent transportation during the period in which they are earned (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). Partnership services are typically billed on a monthly basis, and we generally do not offer extended payment terms. We accrue revenue based on services rendered but not billed for that accounting month.

Billings to BP Products for deficiency volumes under its MVCs, if any, are recorded as deferred revenue and credits, a contract liability, on the consolidated balance sheets, as BP Products has the right to make up the deficiency volumes within the measurement period specified by the agreements. Deferred revenue under these arrangements is recognized into revenue once it is deemed remote that the customer will meet its required annual MVC. If the customer does satisfy its MVC by shipping the deficiency volumes within the same calendar year, it may receive a refund of excess payments.

(in millions of dollars, unless otherwise indicated)

We recognized $13.2 million, $5.6 million and $8.0 million of deficiency revenue under the throughput and deficiency agreements with BP Products for the years ended December 31, 2020, 2019 and 2018, respectively.

Allowance Oil

The tariff for crude oil transportation at BP2 includes a fixed loss allowance ("FLA"). An FLA factor per barrel, a fixed percentage, is a separate fee that is considered a part of the transaction price under the applicable crude oil tariff to cover evaporation and other losses in transit. The amount of revenue recognized is a product of the quantity transported, the applicable FLA factor and the settlement price during the month the product is transported.

The settlement price for volumes accumulated is determined using a summation of the calendar-month average of West Texas Intermediate ("WTI") on the New York Mercantile Exchange with pricing input from the month of movement, pursuant to a related party agreement that we entered into with our affiliate. The settlement price is fixed and determinable upon the completion of transportation. We settle the allowance oil at the end of each period. The balances are entirely recorded in Accounts receivable - related parties in the consolidated balance sheets.

In the years ended December 31, 2020, 2019 and 2018, we recognized revenue of $5.8 million, $10.3 million and $8.8 million, respectively, related to the FLA arrangements with our Parent.

Disaggregation of Revenue

The following table provides information about disaggregated revenue:

	Year Ended December 31,		
Disaggregation of revenue	**2020**	**2019**	**2018**
Transportation services revenue - third parties	2.9	$ 3.0	$ 2.8
Transportation services revenue - related parties	126.0	125.5	113.6
Total revenue	$ 128.9	$ 128.5	$ 116.4

Future Performance Obligations

The values in the table below represent the fixed portion of the MVC arrangements with our existing customer contracts, summarized as future performance obligations as of December 31, 2020. The unfulfilled performance obligations included in the table below are expected to be recognized in revenue in the specified periods:

Unfulfilled performance obligations	**As of December 31, 2020**
2021	$ 106.0
2022	102.2
2023	98.4
Total	$ 306.6

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. Contract liabilities or deferred revenue and credits primarily relate to consideration received from customers for temporary deficiency quantities under minimum volume contracts that the customer has the right to make up in a future period, which we subsequently recognize as revenue or amounts we credit back to the customer in a future period.

The following table provides information about receivables from contracts with customers, contract assets and contract liabilities:

	As of December 31,	
Contract balances	**2020**	**2019**
Receivables from contracts with customers - third parties	$ 0.2	$ 0.6
Receivables from contracts with customers - related parties	11.0	11.3
Deferred revenue and credits - related parties	1.8	1.5

Deferred revenue and credits on our consolidated balance sheets as of December 31, 2020 and 2019 were credited to customers' invoices in January 2021 and January 2020, respectively.

5. Leases

Beginning January 1, 2019, operating ROU assets and operating lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. Because our leases do not provide an explicit rate of return, we use our incremental borrowing rate based on lease term information available at the commencement date in determining the present value of lease payments.

We have a total of four operating leases related to office space of which the term of two expires in 2036 and the other two in 2023. We have the option to terminate our leases 30 days after providing written notice of the election to terminate to the landlord. Two of our leases include a right of renewal and an annual 3% escalation on the anniversary date of lease inception. We have the option to renew our leases by giving notice to landlord not less than 60 days prior to the expiration of the lease term. We have not included the option to renew the leases in our determination of lease term because at the time of lease inception it was not certain we would exercise the renewal. We have included the variable lease payments based on the escalation percentage from above in the determination of our lease liabilities and our ROU assets. The other two leases include a non-lease component for maintenance expense. No leases include a residual value guarantee or provide us an option to acquire the real property at the end of the lease. We have no material subleasing arrangements.

For the years ended December 31, 2020, 2019 and 2018, lease expense totaled $71 thousand, $71 thousand and $61 thousand, respectively.

In November 2020, two operating leases were renewed, and lease terms were extended until 2023, resulting in additional ROU assets and lease liabilities of $94 thousand.

Amounts recognized in the accompanying consolidated balance sheets are as follows:

Lease activity (in thousands)	**Balance sheet location**	**December 31, 2020**	**December 31, 2019**
ROU assets	Other assets	$ 513	$ 469
Current lease liability	Other current liabilities	$ 62	$ 60
Long-term lease liability	Other liabilities	$ 467	$ 417

As of December 31, 2020, the weighted average discount rate of our leases was 4.0% and the weighted average remaining lease term was 13.2 years.

The undiscounted future minimum lease payments and total lease liabilities as of December 31, 2020 are presented in the table below:

(In thousands)		December 31, 2020
2021	$	64
2022		65
2023		66
2024		35
2025		36
Remaining years		443
Undiscounted future minimum lease payments		709
Less: Interest		(180)
Total lease liabilities	$	529

6. Equity Method Investments

We account for our ownership interests in Mars, Ursa, KM Phoenix and the Mardi Gras Joint Ventures using the equity method for financial reporting purposes. Our financial results include our proportionate share of the net income of Mars, Ursa, KM Phoenix and the Mardi Gras Joint Ventures, which is reflected in Income from equity method investments on the consolidated statements of operations. We did not record any impairment loss on our equity method investments during the years ended 2020, 2019 or 2018.

The table below summarizes the balances and activities related to each of our equity method investments ("EMI") that we recorded for the years ended December 31, 2020, 2019 and 2018:

	2020						
	Percentage ownership at year end		Distributions received		Income from EMI		Carrying value at year end
Mars	28.5 %	$	(49.1)	$	46.3	$	54.1
Caesar[1]	56.0 %		(16.1)		15.2		116.5
Cleopatra[1]	53.0 %		(8.9)		5.6		114.3
Proteus[1]	65.0 %		(20.5)		13.6		68.4
Endymion[1]	65.0 %		(24.3)		22.6		79.3
Others[2]	Various		(6.4)		7.5		87.3
Total Equity Investments		$	(125.3)	$	110.8	$	519.9

	2019						
	Percentage ownership at year end		Distributions received		Income from EMI		Carrying value at year end
Mars	28.5 %	$	(53.4)	$	51.1	$	56.9
Caesar[1]	56.0 %		(19.5)		17.5		117.4
Cleopatra[1]	53.0 %		(11.0)		9.0		117.6
Proteus[1]	65.0 %		(19.0)		13.0		75.3
Endymion[1]	65.0 %		(16.8)		15.3		81.0
Others[2]	Various		(11.7)		10.8		86.2
Total Equity Investments		$	(131.4)	$	116.7	$	534.4

(in millions of dollars, unless otherwise indicated)

	2018				
	Percentage ownership at year end	Cumulative effect of accounting change (3)	Distributions received	Income from EMI	Carrying value at year end
Mars	28.5 %	$ (2.8)	$ (47.5)	$ 43.9	$ 59.1
Caesar(1)	56.0 %	—	(21.0)	16.8	119.4
Cleopatra(1)	53.0 %	—	(10.5)	6.5	119.6
Proteus(1)	65.0 %	—	(18.1)	12.3	81.3
Endymion(1)	65.0 %	—	(18.0)	12.3	82.5
Others(2)	Various	—	(2.7)	2.6	87.1
Total Equity Investments		$ (2.8)	$ (117.8)	$ 94.4	$ 549.0

(1) These investments are held by our investment in Mardi Gras which increased to 65% from 20% on October 1, 2018. See Note 3 - *Acquisitions* for further detail.
(2) Includes ownership interest in Ursa (22.7%) and KM Phoenix (25%) acquired on October 1, 2018.
(3) The financial results of Mars reflect the adoption of FASB Accounting Standards Codification Topic 606 "Revenue from Contracts with Customers" on January 1, 2018 under the modified retrospective transition method through a cumulative adjustment to equity. Our cumulative effect impact from this accounting change to our Mars investment was $(2.8) million, offset to equity. The Mardi Gras Joint Ventures and Ursa adopted this ASU on January 1, 2019, and there was no cumulative effect impact from the adoption. KM Phoenix adopted Topic 606 on January 1, 2018, and there was no cumulative effect impact from the adoption.

The following tables present aggregated selected balance sheet and income statement data for our equity method investments on a 100% basis for the years ended December 31, 2020, 2019 and 2018 and as of December 31, 2020 and 2019:

	For the Year Ended December 31,		
	2020	2019	2018
Statement of operations			
Revenue	$ 538.6	$ 560.5	$ 470.8
Operating expenses	250.2	246.0	200.9
Net income	288.9	317.2	270.4

	As of December 31,	
Balance Sheets	2020	2019
Current assets	110.8	128.7
Non current assets	1,726.4	1,630.7
Current liabilities	56.5	49.6
Non current liabilities	589.4	493.0
Equity	1,191.3	1,216.8

(in millions of dollars, unless otherwise indicated)

7. Property, Plant and Equipment

Property, plant and equipment consisted of the following:

	December 31,	
	2020	2019
Land	$ 0.2	$ 0.2
Rights-of-way assets	1.4	1.4
Buildings and improvements	6.9	6.9
Pipelines and equipment	95.3	94.4
Other	0.8	0.5
Construction in progress	7.1	0.6
Property, plant and equipment	111.7	104.0
Less: Accumulated depreciation	(43.8)	(41.3)
Property, plant and equipment, net	$ 67.9	$ 62.7

During the year ended December 31, 2019, an impairment charge of $4.4 million, before insurance recoveries, was recorded under "Impairment and other, net" on our consolidated statements of operations. See Note 13 - *Commitments and Contingencies*.

There were no impairments on property, plant and equipment for the years ended December 31, 2020 and 2018.

8. Other Current Liabilities

Other current liabilities consist of the following:

	December 31,	
	2020	2019
Accrued capital expenditures	$ 4.1	$ 0.2
Accrued interest payable - related parties	0.9	4.2
Current portion of environmental remediation obligation	0.4	0.6
Current portion of lease liabilities	0.1	0.1
Accrued liabilities	2.3	1.5
Other current liabilities	$ 7.8	$ 6.6

9. Debt

On October 30, 2017, the Partnership entered into a $600.0 million unsecured revolving credit facility agreement (the “credit facility”) with an affiliate of BP. The credit facility terminates on October 30, 2022 and provides for certain covenants, including the requirement to maintain a consolidated leverage ratio, which is calculated as total indebtedness to consolidated EBITDA (as defined in the credit facility), not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. In addition, the limited liability company agreement of the Partnership's general partner requires the approval of BP Holdco prior to the incurrence of any indebtedness that would cause the Partnership's leverage ratio to exceed 4.5 to 1.0.

The credit facility also contains customary events of default, such as (i) nonpayment of principal when due, (ii) nonpayment of interest, fees or other amounts, (iii) breach of covenants, (iv) misrepresentation, (v) cross-payment default and cross-acceleration (in each case, to indebtedness in excess of $75.0 million) and (vi) insolvency. Additionally, the credit facility limits our ability to, among other things: (i) incur or guarantee additional debt, (ii) redeem or repurchase units or make distributions under certain circumstances; and (iii) incur certain liens or permit them to exist. Indebtedness under this facility bears interest at the 3-month LIBOR plus 0.85%. Once a request to borrow is completed, our interest rate is fixed through the maturity date of the borrowing, typically six months. This facility includes customary fees, including a commitment fee of 0.10% and a utilization fee of 0.20%. There is no debt issuance cost associated with the credit facility.

On October 1, 2018, the Partnership borrowed $468.0 million under the credit facility to fund our acquisition.

On February 24, 2020, the Partnership entered into a $468.0 million Term Loan Facility Agreement ("term loan") with an affiliate of BP. On March 13, 2020, proceeds were used to repay outstanding borrowings under the existing credit facility. The term loan has a final repayment date of February 24, 2025, and provides for certain covenants, including the requirement to maintain a consolidated leverage ratio, which is calculated as total indebtedness to consolidated EBITDA, not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. Simultaneous with this transaction, we entered into a First Amendment to Short Term Credit Facility Agreement ("First Amendment") whereby the lender added a provision that indebtedness under both the term loan and credit facility shall not exceed $600.0 million. All other terms of the credit facility remain the same.

As of December 31, 2020, the Partnership was in compliance with the covenants contained in the credit facility and term loan. The weighted average interest rate for our long-term debt was 1.70% and 3.25% at December 31, 2020 and 2019, respectively.

For the years ended December 31, 2020, 2019 and 2018, interest and fees incurred were $8.3 million, $16.5 million and $4.8 million, respectively.

10. Related Party Transactions

Related party transactions include transactions with our Parent and our Parent’s affiliates, including those entities in which our Parent has an ownership interest but does not have control. In addition to the fixed loss allowance arrangements discussed in Note 4 - *Revenue Recognition* and the credit facilities in Note 9 - *Debt*, we have entered into the following transactions with our related parties:

Omnibus Agreement

The Partnership has entered into an omnibus agreement with BP Pipelines and certain of its affiliates, including the general partner. This agreement addresses, among other things, (i) the Partnership's obligation to pay an annual fee for general and administrative services provided by BP Pipelines and its affiliates, (ii) the Partnership's obligation to reimburse BP Pipelines for personnel and other costs related to the direct operation, management and maintenance of the assets and (iii) the Partnership's obligation to reimburse BP Pipelines for services and certain direct or allocated costs and expenses incurred by BP Pipelines or its affiliates on behalf of the Partnership.

Pursuant to the omnibus agreement, BP Pipelines will indemnify the Partnership and fund the costs of required remedial action for its known historical and legacy spills and releases and other environmental and litigation claims identified in the omnibus agreement.

The omnibus agreement also addresses the Partnership's right of first offer to acquire BP Pipelines' retained ownership interest in Mardi Gras and all of BP Pipelines' interests in midstream pipeline systems and assets related thereto in the contiguous United States and offshore Gulf of Mexico that are owned by BP Pipelines at the closing of the IPO.

Further, the omnibus agreement addresses the granting of a license from BPA to the Partnership with respect to use of certain BP trademarks and trade name.

Related Party Revenue

We provide crude oil, refined products and diluent transportation services to related parties and generate revenue through published tariffs.

Effective July 1, 2017, we entered into a throughput and deficiency agreement with BP Products for transporting diluent on the Diamondback pipeline under two throughput and deficiency agreements and a dedication agreement. The dedication agreement with a third-party on Diamondback automatically renewed in 2021 and will now expire in June 2022. This contract is subject to successive one-year renewal periods at the election of the parties. The throughput and deficiency agreement for Diamondback automatically renewed in 2021 and will now expire in June 2022.

On October 30, 2017, we entered into additional throughput and deficiency agreements with BP Products for each of our three wholly owned pipeline systems: BP2, River Rouge and Diamondback. Under these fee-based agreements, we provide transportation services to BP Products, in exchange for BP Products' commitment to pay us the applicable tariff rates for the minimum monthly volumes, whether or not such volumes are physically shipped by BP Products through our pipelines. BP Products is allowed to make up for the monthly deficiency within the same calendar year during the initial term ending December 31, 2020. Adjustment to the monthly deficiency payments remitted to us by BP Products, if any, is determined at the end of each calendar year based on the actual volume transported during such period. These agreements expired on December 31, 2020.

On November 3, 2020, the Partnership entered into throughput and deficiency agreements with BP Products with respect to volumes transported on BP2, River Rouge and Diamondback. These new agreements have a term of three years beginning January 1, 2021 and expiring December 31, 2023.

Our revenue from related parties was $126.0 million, $125.5 million and $113.6 million for the years ended December 31, 2020, 2019 and 2018, respectively.

We recognized $13.2 million, $5.6 million and $8.0 million of deficiency revenue under the throughput and deficiency agreements with BP Products for the years ended December 31, 2020, 2019 and 2018, respectively. At December 31, 2020 and 2019, there was $1.8 million and $1.5 million, respectively, of deferred revenue and credits recorded in relation to these agreements.

Related Party Expenses

All employees performing services on behalf of our operations are employees of our Parent. Our Parent also procures our insurance policies on our behalf and performs certain general corporate functions for us related to finance, accounting, treasury, legal, information technology, human resources, shared services, government affairs, insurance, health, safety, security, employee benefits, incentives, severance and environmental functional support. Personnel and operating costs incurred by our Parent on our behalf are included in either Operating expenses – related parties or General and administrative – related parties in the consolidated statements of operations, depending on the nature of the service provided.

We paid our Parent an annual fee of $14.0 million, $13.6 million and $13.3 million in 2020, 2019 and 2018, respectively, under the omnibus agreement. The annual fee was adjusted to $15.2 million, payable in equal monthly installments, beginning on January 1, 2020. During the second quarter of 2020, our Parent agreed to adjust the fee payable under the Omnibus Agreement back to the 2019 annual fee, beginning in the second quarter, prorated for the remainder of 2020 due to the ongoing economic effects of the global COVID-19 pandemic. This resulted in a 2020 annual fee of $14.0 million. The annual fee was adjusted to $15.5 million per year, payable in equal monthly installments, beginning on January 1, 2021.

Our general partner may adjust the administrative fee to reflect, among others, any change in the level or complexity of our operations, a change in the scope or cost of services provided to us, inflation or a change in law or other regulatory requirements, the contribution, acquisition or disposition of our assets or any material change in our operation activities.

We also reimburse our Parent for personnel and other costs related to the direct operation, management and maintenance of the assets and services and certain direct or allocated costs and expenses incurred by our Parent or its affiliates on our behalf pursuant to the terms in the omnibus agreement.

During the years ended December 31, 2020, 2019 and 2018, we recorded the following amounts for related party expenses, which also included the expenses related to pension and retirement savings plans and share-based compensation discussed below:

(in millions of dollars, unless otherwise indicated)

	Years Ended December 31,		
	2020	2019	2018
Operating expenses—related parties	$ 5.3	$ 5.8	$ 5.0
Maintenance expenses—related parties	0.4	0.3	0.1
General and administrative—related parties	14.5	14.1	14.1
Total operating, maintenance, and general corporate costs—related parties	$ 20.2	$ 20.2	$ 19.2

Non-controlling Interests

Non-controlling interests consist of the 35% ownership interest in Mardi Gras held by our Parent at December 31, 2020, 2019 and 2018 compared to the 80% ownership interest held before completion of the acquisition on October 1, 2018.

Net income attributable to non-controlling interests is the product of the non-controlling interests ownership percentage and the net income of Mardi Gras. We report Non-controlling interests as a separate component of equity on our consolidated balance sheets and Net income attributable to non-controlling interests on our consolidated statements of operations.

11. Distributions and Net Income Per Unit

The following table details the distributions declared and/or paid for the periods presented:

Three Months Ended	Date Paid or to be Paid	General Partner**	Limited Partners' Common Units	Limited Partners' Subordinated Units	Total	Distributions per Limited Partner Unit (in dollars)
December 31, 2017*	February 15, 2018	$ —	$ 9.4	$ 9.3	$ 18.7	$ 0.1798
March 31, 2018	May 15, 2018	—	14.0	14.0	28.0	0.2675
June 30, 2018	August 15, 2018	—	14.3	14.3	28.6	0.2725
September 30, 2018	November 15, 2018	—	15.3	15.3	30.6	0.2915
December 31, 2018	February 14, 2019	—	15.8	15.8	31.6	0.3015
March 31, 2019	May 15, 2019	0.2	16.4	16.3	32.9	0.3126
June 30, 2019	August 14, 2019	0.4	16.9	17.0	34.3	0.3237
September 30, 2019	November 14, 2019	0.7	17.6	17.6	35.9	0.3355
December 31, 2019	February 13, 2020	1.2	18.2	18.2	37.6	0.3475
March 31, 2020	May 14, 2020	1.2	18.2	18.2	37.6	0.3475
June 30, 2020	August 13, 2020	1.2	18.2	18.2	37.6	0.3475
September 30, 2020	November 12, 2020	1.2	18.2	18.2	37.6	0.3475
December 31, 2020	February 11, 2021	1.2	18.2	18.2	37.6	0.3475

* For the period subsequent to IPO Oct 30, 2017 – Dec 31, 2017, prorated from minimum quarterly distribution amount of $0.2625 / unit.
** Due to rounding, numbers presented for the general partner may not precisely reflect the absolute figures.

Earnings in excess of distributions are allocated to the limited partners based on their respective percentage interests. Payments made to the Partnership's unitholders are determined in relation to actual distributions declared and are not based on the net income allocations used in the calculation of net income per unit.

In addition to the common and subordinated units, the Partnership also identified the incentive distribution rights ("IDRs") currently held by the general partner as a participating security and uses the two-class method when calculating the net income per unit that is based on the weighted-average number of common units outstanding during the period.

When calculating basic earnings per unit under the two-class method for a master limited partnership, net income for the current reporting period is reduced by the amount of available cash that will be distributed to the general partner and limited partners for that reporting period. The following tables show the allocation of net income to arrive at net income per unit for the years ended December 31, 2020, 2019 and 2018:

	For the years ended December 31,		
	2020	**2019**	**2018**
Net income attributable to the Partnership	$ 168.4	$ 167.9	$ 133.1
Less:			
Incentive distribution rights currently held by the general partner	4.8	2.5	—
Limited partners' distribution declared on common units	72.8	69.1	59.4
Limited partners' distribution declared on subordinated units	72.8	69.1	59.4
Net income attributable to the Partnership in excess of distributions	$ 18.0	$ 27.2	$ 14.3

	For the year ended December 31, 2020			
	General Partner	**Limited Partners' Common Units**	**Limited Partners' Subordinated Units**	**Total**
Distributions declared	$ 4.8	$ 72.8	$ 72.8	$ 150.4
Net income attributable to the Partnership in excess of distributions	—	9.0	9.0	18.0
Net income attributable to the Partnership	$ 4.8	$ 81.8	$ 81.8	$ 168.4
Weighted average units outstanding (in millions):				
Basic and Diluted		52.4	52.4	104.8
Net income per limited partner unit (in dollars):				
Basic and Diluted		$ 1.56	$ 1.56	

	For the year ended December 31, 2019			
	General Partner	**Limited Partners' Common Units**	**Limited Partners' Subordinated Units**	**Total**
Distributions declared	$ 2.5	$ 69.1	$ 69.1	$ 140.7
Net income attributable to the Partnership in excess of distributions	—	13.6	13.6	27.2
Net income attributable to the Partnership	$ 2.5	$ 82.7	$ 82.7	$ 167.9
Weighted average units outstanding (in millions):				
Basic and Diluted		52.4	52.4	104.8
Net income per limited partner unit (in dollars):				
Basic and Diluted		$ 1.58	$ 1.58	

	Year Ended December 31, 2018			
	General Partner	Limited Partners' Common Units	Limited Partners' Subordinated Units	Total
Distributions declared	$ —	$ 59.4	$ 59.4	$ 118.8
Net income attributable to the Partnership in excess of distributions	—	7.2	7.1	14.3
Net income attributable to the Partnership	$ —	$ 66.6	$ 66.5	$ 133.1
Weighted average units outstanding (in millions):				
Basic and Diluted		52.4	52.4	104.8
Net income per limited partner unit (in dollars):				
Basic and Diluted		$ 1.27	$ 1.27	

12. Fair Value Measurements

The carrying amounts of accounts receivable, other current assets, accounts payable, and other current liabilities approximate their fair values due to their short-term nature.

The carrying value of borrowings under the term loan as of December 31, 2020, and the credit facility as of December 31, 2019, approximate fair value as the interest rates are reflective of market rates.

13. Commitments and Contingencies

Legal Proceedings

The Partnership is a party to ongoing legal proceedings in the ordinary course of business. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity.

In addition, pursuant to the terms of the various agreements under which we acquired assets from BP since the IPO, BP will indemnify us for certain liabilities relating to litigation and environmental matters attributable to the ownership or operation of the acquired assets prior to our acquisition of those assets.

Indemnification

Under our omnibus agreement, our Parent will indemnify us for certain environmental liabilities, litigation and other matters attributable to the ownership or operation of our assets prior to our ownership. For the purposes of determining the indemnified amount of any loss suffered or incurred by the Partnership, the Partnership's ownership of 28.5% in Mars and 65% in Mardi Gras, and Mardi Gras' 56% ownership in Caesar, 53% ownership in Cleopatra, 65% ownership in Endymion and 65% ownership in Proteus will be considered. Indemnification for certain identified environmental liabilities is subject to a cap of $25.0 million without any deductible. Other matters covered by the omnibus agreement are subject to a cap of $15.0 million and an aggregate deductible of $0.5 million before we are entitled to indemnification. Indemnification for any unknown environmental liabilities was limited to liabilities due to occurrences on or before October 30, 2017, which were identified prior to October 30, 2020. We continue to maintain indemnification by our general partner for matters previously discovered. To the extent that unknown environmental liabilities arise relating to prior ownership, the Partnership will be liable.

The Interest Purchase Agreement contains customary representations, warranties and covenants of our Parent and the Partnership. Our Parent, on the one hand, and the Partnership, on the other hand, have agreed to indemnify each other and their respective affiliates, officers, directors and other representatives against certain losses, including those resulting from any breach of their representations, warranties or covenants contained in the Interest Purchase Agreement, subject to certain limitations and survival periods. This agreement covers the Partnership's ownership of 22.7% in Ursa and 25% in KM Phoenix.

(in millions of dollars, unless otherwise indicated)

Environmental Matters

We are subject to federal, state, and local environmental laws and regulations. We record provisions for environmental liabilities based on management's best estimates, using all information that is available at the time. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us and potential third-party liability claims. Often, as the remediation evaluation and effort progress, additional information is obtained, requiring revisions to estimated costs. We are indemnified by our Parent under the omnibus agreement against environmental cleanup costs for incidents that occurred prior to our ownership. Revisions to the estimated environmental liability for conditions that are not indemnified under the omnibus agreement with our Parent are reflected in our consolidated statements of operations in the year in which they are probable and reasonably estimable.

We accrued $3.4 million and $3.7 million for environmental liabilities at December 31, 2020 and 2019, respectively. These balances are broken down on the consolidated balance sheets as follows:

		December 31,	
	Balance sheet location	**2020**	**2019**
Current portion of environmental remediation obligations	Other current liabilities	$ 0.4	$ 0.6
Long-term portion of environmental remediation obligations	Other liabilities	3.0	3.1
Total		$ 3.4	$ 3.7

The balances are related to incidents that occurred prior to our ownership and are entirely indemnified by our Parent. As a result, we recorded corresponding indemnification assets of $3.4 million and $3.7 million on the consolidated balance sheet as of December 31, 2020, and 2019, respectively. These balances are broken down on the consolidated balance sheets as follows:

		December 31,	
	Balance sheet location	**2020**	**2019**
Current portion of indemnification assets	Other current assets	$ 0.4	$ 0.6
Non-current portion of indemnification assets	Other assets	3.0	3.1
Total		$ 3.4	$ 3.7

Griffith Station Incident

On June 13, 2019, a building fire occurred at the Griffith Station on BP2. Management performed an evaluation of the assets and determined that an impairment was required. A charge of $4.4 million for the impairment was recorded under "Impairment and other, net" on our consolidated statements of operations for the year ended December 31, 2019. In addition, we incurred $1.6 million as a response expense for the year ended December 31, 2019. Our assets are insured with a deductible of $1.0 million per incident. We accrued an offsetting insurance receivable of $5.0 million resulting in a net charge of $1.0 million to "Impairment and other, net" for the year ended December 31, 2019. The insurance receivable was recorded as $4.3 million under "Other current assets" and $0.7 million under "Other assets" on our consolidated balance sheet as of December 31, 2019.

During the year ended December 31, 2020, we incurred $0.4 million for response expense and received $2.9 million of insurance proceeds. The proceeds have been recorded under "Proceeds from insurance claims" in our consolidated statements of cash flows for the year ended December 31, 2020, leaving a balance of $2.5 million recorded under "Other current assets" on our consolidated balance sheets as of December 31, 2020, for insurance proceeds expected to be received in 2021. In the event that insurance proceeds exceed the receivable balance, such amounts would be recognized as a gain.

Commitments

We hold easements or rights-of-way ("ROWs") arrangements from landowners permitting the use of land for the construction and operation of our pipeline systems.

We incurred ROWs expenses, operating lease expenses and service contract expenses of $0.2 million for the years ended December 31, 2020, 2019 and 2018, respectively. Such amounts are included in Operating expenses – third parties on the consolidated statements of operations.

(in millions of dollars, unless otherwise indicated)

These ROWs are not within the scope of ASC 842. At December 31, 2020, our future minimum commitment for contracts in excess of one year is as follows:

	Total	2021	2022	2023	2024	2025	Thereafter
Rights-of-way	$ 3.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 2.5
Total	$ 3.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 2.5

14. Transactions with Major Customers and Concentration of Credit Risk

Our Parent accounted for 97.8%, 97.7% and 97.6% of our total revenues for the years ended December 31, 2020, 2019 and 2018, respectively. We are potentially exposed to concentration of credit risk primarily through our accounts receivable from our Parent for the pipeline transportation services that we provide. These receivables have payment terms of 30 days or less. We have no history of collectability issues with our Parent.

We have a concentration of trade receivables due from customers in the oil and gas industry, which may impact our overall exposure to credit risk as they may be similarly affected by changes in economic, regulatory and other factors. We manage our exposure to credit risk through credit analysis, credit limit approvals and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. As of December 31, 2020 and 2019, there were no such arrangements.

We have concentrated credit risk for cash by maintaining deposits with an affiliate of BP and a major bank. Amounts on deposit in the major bank may at times exceed amounts covered by insurance provided by the United States Federal Deposit Insurance Corporation ("FDIC"). We monitor the financial health of the affiliate and major bank and have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk. At December 31, 2020 and 2019, we had $126.7 million and $98.6 million in cash and cash equivalents in excess of FDIC limits, respectively.

15. Unit-Based Compensation

Long-Term Incentive Plan

On October 26, 2017, we adopted BP Midstream Partners LP 2017 Long Term Incentive Plan (the “LTIP”). Awards under the LTIP are available for eligible officers, directors, employees and consultants of the general partner and its affiliates, who perform services for the Partnership. The LTIP allows the Partnership to grant unit options, unit appreciation rights, restricted units, phantom units, unit awards, cash awards, performance awards, distribution equivalent rights, substitute awards and other unit-based awards. The maximum aggregate number of common units that may be issued pursuant to the awards granted under the LTIP shall not exceed 5,502,271, subject to proportionate adjustment in the event of unit splits and similar events.

Unit-Based Awards under the LTIP

Phantom units vest on the first anniversary of the date of grant. As a part of the phantom unit awards, the grantees will also receive distribution equivalent rights that entitle them, prior to vesting, with distributions for the same amounts that are distributed to the common unit holders. Distribution equivalent rights accrue in the form of either cash or additional phantom units. These phantom units do not convey voting rights.

The following is a summary of phantom unit award activities of the Partnership’s common units from 2018 to 2020:

	Phantom Units		
	Number of Units	Weighted Average Grant Date Fair Value per Unit (in dollars)	Aggregate Fair Value (in thousands)
Outstanding at December 31, 2017	8,468	$ 17.48	
Granted	3,737	20.07	$ 75
Vested	(8,468)	17.48	
Outstanding at December 31, 2018	3,737	20.07	
Granted	15,227	16.64	$ 253
Vested	(3,737)	20.07	
Outstanding at December 31, 2019	15,227	16.64	
Granted	16,038	14.03	$ 225
Vested	(15,227)	16.64	
Outstanding at December 31, 2020	16,038	$ 14.03	

Total compensation expense recognized for phantom unit awards were $232 thousand, $239 thousand and $177 thousand for 2020, 2019 and 2018, respectively. These amounts are included in General and administrative – related parties on the consolidated statements of operations.

The unrecognized compensation cost related to phantom unit awards was $34 thousand at December 31, 2020, which is expected to be recognized over a weighted average period of 0.2 years.

There were no forfeitures in the years ended December 31, 2020, 2019 and 2018.

16. Variable Interest Entity

Mardi Gras is a Delaware limited liability company and a pass-through entity for federal and state income tax purposes. Mardi Gras holds equity interests in the Mardi Gras Joint Ventures and accounts for them as equity method investments. Mardi Gras does not have any other operations or activities. The remaining interests in each of the Mardi Gras Joint Ventures are owned by unaffiliated third-party investors. Each of the Mardi Gras Joint Ventures is managed by their respective management committee, and decisions made by these management committees require approval of two or more members that are not affiliates with equity interest holdings meeting certain thresholds.

On October 30, 2017, our Parent contributed to us 20% of its economic interest and 100% of its managing member interest in Mardi Gras. The remainder of the economic interest in Mardi Gras was held 79% by BP Pipelines and 1% by an affiliate of BP. Through our managing member interest in Mardi Gras, we have the right to vote 100% of Mardi Gras' interest in each of the Mardi Gras Joint Ventures. We determined that Mardi Gras is a variable interest entity because (i) we hold disproportional voting rights as compared to our economic interest in Mardi Gras, and (ii) substantially all of Mardi Gras' activities involve or are conducted on behalf of our Parent, which holds disproportionately few voting rights.

On October 1, 2018, pursuant to the Interest Purchase Agreement we completed the acquisition of an additional 45% interest in Mardi Gras from BP Pipelines. This reduced the non-controlling interest on Mardi Gras from 80% to 35%.

The managing member interest in Mardi Gras provides us with the unilateral power to direct the activities of Mardi Gras that most significantly impact its economic performance including the right to exercise the voting rights of BP for each of the Mardi Gras Joint Ventures. In addition, our obligations to absorb the expected losses of and the right to receive the residual returns from Mardi Gras relative to our economic ownership is significant to Mardi Gras. As a result, we are the primary beneficiary of Mardi Gras and consolidate Mardi Gras.

We have the obligation to provide financial support to Mardi Gras if all members unanimously determine that additional capital contributions are necessary to fund Mardi Gras' operations. The assets of Mardi Gras can only be used to satisfy its own obligations, which were zero at December 31, 2020 and 2019. Under the current limited liability company agreement of Mardi Gras, creditors of Mardi Gras, if any, do not have any recourse to the general credit of the Partnership.

(in millions of dollars, unless otherwise indicated)

The financial position of Mardi Gras as of December 31, 2020 and 2019 and its financial performance and cash flows for each of the three years ended December 31, 2020, 2019 and 2018, as reflected in our consolidated financial statements, are as follows:

	As of December 31,	
	2020	2019
Balance sheet		
Equity method investments	$ 378.5	$ 391.3
Non-controlling interests	132.5	136.9

	December 31,		
	2020	2019	2018
Statement of operations			
Income from equity method investments	$ 57.0	$ 54.8	$ 47.9
Less: Net income attributable to non-controlling interests	19.9	19.2	32.6
Net impact on Net income attributable to the Partnership	$ 37.1	$ 35.6	$ 15.3

	December 31,		
	2020	2019	2018
Statement of cash flows			
Cash flows from operating activities			
Distributions of earnings received from equity method investments	$ 57.0	$ 54.8	$ 47.9
Cash flows from investing activities			
Distribution in excess of earnings from equity method investments	12.8	11.5	19.7
Cash flows from financing activities			
Distributions to non-controlling interests	(24.3)	(23.2)	(46.4)
Net change on BPMP's cash and cash equivalents	$ 45.5	$ 43.1	$ 21.2

17. Subsequent Events

We have evaluated subsequent events through the issuance of these consolidated financial statements. Based on this evaluation, it was determined that no subsequent events occurred, other than the items noted below, that require recognition or disclosure in the consolidated financial statements.

Distribution

On February 11, 2021, we paid a cash distribution of $0.3475 per limited partner unit to unitholders of record on January 28, 2021, for the three months ended December 31, 2020. The total distribution paid was $37.6 million, with $16.6 million distributed to our non-affiliated common unitholders and $21.0 million, including $1.2 million for IDRs, distributed to our Parent in respect of its ownership of our common units, subordinated units and IDRs.

Subordinated Unit Conversion

On January 29, 2021, the board of directors of our general partner confirmed and approved that, following the distribution mentioned above with respect to the three months ended December 31, 2020, the financial tests required for conversion of our subordinated units had been met under the terms of the partnership agreement. Accordingly, effective February 12, 2021, the first business day following the payment of the distribution, all of our subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, is responsible for evaluating the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective.

Management's Report on Internal Control Over Financial Reporting

The management of our general partner, with the participation of our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over our financial reporting, as such term is defined under Exchange Act Rule 13a-15(f). Our internal control system was designed to provide reasonable assurance to the management of our general partner regarding the preparation and fair presentation of published financial statements.

In evaluating the effectiveness of our internal control over financial reporting as of December 31, 2020, the management of our general partner used the criteria established in the UK Financial Reporting Council’s Guidance on Risk Management, Internal Control and Related Financial and Business Reporting. As a result of this assessment and based on the criteria in the UK Financial Reporting Council’s Guidance, management of our general partner has concluded that, as of December 31, 2020, our internal control over financial reporting was effective.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal control over financial reporting, which is contained herein.

Changes in Internal Control Over Financial Reporting

There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of BP Midstream Partners GP LLC and the
Partners of BP Midstream Partners LP

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of BP Midstream Partners LP and subsidiaries (the “Partnership”) as of December 31, 2020, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting. In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in the UK Financial Reporting Council's Guidance.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2020 of the Partnership and our report dated February 25, 2021 expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2021

Item 9B. OTHER INFORMATION

Appointment of Chief Financial Officer

On February 24, 2021, the Board of Directors of BP Midstream Partners GP LLC (the “General Partner”) appointed Jack Collins as Chief Financial Officer of the General Partner, effective March 1, 2021. In addition to serving as Chief Financial Officer of the General Partner, Mr. Collins will continue to serve as a director of the General Partner.

Mr. Collins, 45, has served as President of BPX Energy since July 2020, prior to which he served as Senior Vice President and Chief Financial Officer of BPX Energy from December 2014. Prior to joining BPX Energy, Mr. Collins held various executive roles in finance and investor relations, including at Denbury Resources, Inc and PostRock Energy Corp. He has more than 20 years’ experience across the energy sector. Mr. Collins has a BA in Economics from the University of Colorado and completed the Advanced Management Program at Harvard Business School.

There are no arrangements or understandings between Mr. Collins and any other persons pursuant to which Mr. Collins was selected as Chief Financial Officer. There are no relationships between Mr. Collins and the General Partner or any of its subsidiaries that would require disclosure pursuant to Item 404(a) of Regulation S-K.

Appointment of Director

Effective March 1, 2021, BP Midstream Partners Holdings LLC, sole member of the General Partner, appointed Ms. Starlee Sykes as a director of the General Partner.

Ms. Sykes, 45, has served as Senior Vice President Gulf of Mexico and Canada for the BP Production & operations organization since January 2021. From February 2018 until December 2020, Ms. Sykes served as BP's Regional President of Gulf of Mexico and Canada, where she held accountability for all safety and business aspects of the offshore hub. From January 2011 until January 2018, Ms. Sykes served as Vice President in BP's Global Projects organization, leading a portfolio of offshore projects and teams. Ms. Sykes joined BP in 1997 and has a BS in Mechanical Engineering from Texas A&M University.

There are no arrangements or understandings between Ms. Sykes and any other persons pursuant to which Ms. Sykes was selected as a director. There are no relationships between Ms. Sykes and the General Partner or any of its subsidiaries that would require disclosure pursuant to Item 404(a) of Regulation S-K.

In connection with the appointment of Starlee Sykes as a director of the General Partner, the General Partner and the Partnership will enter into an Indemnification Agreement with Ms. Sykes pursuant to which the General Partner and the Partnership will be required to indemnify Ms. Sykes to the fullest extent permitted under Delaware law against liability that may arise by reason of her service to the General Partner and the Partnership and to advance her expenses incurred as a result of any proceeding against her to which she could be indemnified.

The foregoing description is qualified in its entirety by reference to the full text of the Indemnification Agreement, the form of which is filed as Exhibit 10.4 to this Annual Report on Form 10-K and incorporated in this Item 9B by reference.

Disclosures Required Pursuant to Section 13(r) of the Securities Exchange Act of 1934

In accordance with our General Business Principles and Code of Conduct, we seek to comply with all applicable international trade laws including applicable sanctions and embargoes.

Under the Iran Threat Reduction and Syria Human Rights Act of 2012, and Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our “affiliates” (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities during the period covered by the report. Because the SEC defines the term “affiliate” broadly, it includes any entity controlled by us as well as any person or entity that controls us or is under common control with us.

The disclosure below relates solely to activities conducted by non-U.S. affiliates of BP p.l.c. that may be deemed to be under common control with us. The disclosure does not relate to any activities conducted directly by us (including our subsidiaries and equity investments), or our general partner and does not involve our or the general partner’s management.

For purposes of this disclosure, we refer to BP p.l.c. and its subsidiaries other than us, the general partner and BP Midstream Partners Holdings LLC as the "BP Group." References to actions taken by the BP Group mean actions taken by the applicable BP Group company. None of the payments disclosed below were made in U.S. dollars, however, for disclosure purposes, all have been converted into U.S. dollars at the appropriate exchange rate. We do not believe that any of the transactions or activities listed below violated U.S. sanctions:

- BP p.l.c. indirectly owns a 29.3% interest in Middle East Lubricants Company LLC ("Melubco"), a non-operated joint venture, manufacturing lubricants in the United Arab Emirates.
  - In November 2018, an Iranian shipping company brought a claim in Iran against a third party for non-payment of shipping fees and obtained a judgment in absentia with a US dollar equivalent value of approximately $60,000.
  - In November 2019, the Consulate General of The Islamic Republic of Iran in Dubai formally notified Melubco that the case had been filed against Melubco.
  - In May 2020, Melubco paid court filing fees to the Tehran Judicial Services Office with a US dollar equivalent value of approximately $2,694. The payment was required to appeal the judgment obtained in absentia, purportedly against Melubco.
  - Melubco refutes the claim on the basis that it has never contracted with or received any services from this shipping company. Melubco does not do, and has never done, business in Iran.
  - In September 2020, the Division 15th Legal Court of Tehran held that the judgment in absentia had not been obtained against Melubco but against a different company (with a similar name), and therefore it could not be enforced against Melubco.
- In July 2018, BP Iran Limited terminated its lease of an office in Tehran. The office had been used for administrative activities. In 2020, taxes with a US dollar equivalent value of approximately $20,000 were paid from a BP trust account held with Tadvin Co. to Iranian public entities. No gross revenues or net profits were attributable to these activities.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Management of BP Midstream Partners LP

We are managed and operated by the board of directors and executive officers of our general partner, BP Midstream Partners GP LLC. Our general partner is controlled by BP Holdco, a wholly owned subsidiary of BP Pipelines. All of the officers and certain of the directors of our general partner are also officers and directors of BP Pipelines or its affiliates. Neither our general partner nor its board of directors is elected by our unitholders. BP Holdco is the sole member of our general partner and has the right to appoint our general partner's entire board of directors, including at least three independent directors meeting the independence standards established by the NYSE. Our unitholders are not entitled to directly participate in our management or operations. Our general partner owes certain contractual duties to our unitholders as well as a fiduciary duty to its owners.

Our general partner has eight directors. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members within one year of the listing of our common units on the NYSE, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act.

All of the executive officers of our general partner listed below allocate their time between managing our business and affairs and the business and affairs of BP Pipelines or its affiliates. The amount of time that our executive officers devote to our business and the business of BP Pipelines or its affiliates will vary in any given year based on a variety of factors though ordinarily we expect that less than 50% will be devoted to our business.

Our operations are conducted through, and our assets are owned by, various subsidiaries. However, neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by BP, BP Pipelines or third parties, but we sometimes refer to these individuals, for drafting convenience only, in this Annual Report as our employees because they provide services directly to us. These operations personnel primarily provide services with respect to the assets we operate: BP2, River Rouge and Diamondback. Mars, the Mardi Gras Joint Ventures, and Ursa are operated by an affiliate of Shell. KM Phoenix is operated by an affiliate of Kinder Morgan.

Neither our general partner nor BP Pipelines receives any management fee or other compensation in connection with our general partner's management of our business, but we reimburse our general partner and its affiliates, including BP Pipelines, for all expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, benefits, bonus, long term incentives and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Please read "Certain Relationships and Related Transactions, and Director Independence-Agreements Governing the Formation Transactions."

Executive Sessions

To facilitate candid discussion among our directors, the non-management directors will meet in regularly scheduled executive sessions. The director who presides at these meetings will be chosen by the board of directors of our general partner prior to such meetings.

Interested Party Communications

Unitholders and other interested parties may communicate by writing to: BP Midstream Partners LP, 501 Westlake Park Boulevard, Houston, Texas 77079. Unitholders may submit their communications to the board of directors of our general partner, any committee of the board of directors of our general partner or individual directors on a confidential or anonymous basis by sending the communication in a sealed envelope marked "Unitholder Communication with Directors" and clearly identify the intended recipient(s) of the communication.

Our Chief Legal Counsel and Secretary will review each communication from unitholders and other interested parties and will forward the communication, as expeditiously as reasonably practicable, to the addressees if: (1) the communication complies with the requirements of any applicable policy adopted by the board of directors relating to the subject matter of the communication; and (2) the communication falls within the scope of matters generally considered by the board of directors. To the extent the subject matter of a communication relates to matters that have been delegated by the board of directors to a committee or to an executive officer of the general partner, then the general partner's Chief Legal Counsel and Secretary may forward the communication to the executive officer or chairman of the committee to which the matter has been delegated. The acceptance and forwarding of communications to the members of the board of directors or an executive officer does not imply or create any fiduciary duty of the board members or executive officer to the person submitting the communications.

Information may be submitted confidentially and anonymously, although we may be obligated by law to disclose the information or identity of the person providing the information in connection with government or private legal actions and in other circumstances. Our policy is not to take any adverse action, and not to tolerate any retaliation, against any person for asking questions or making good faith reports of possible violations of law, our policies or our Corporate Code of Business Conduct and Ethics.

Available Governance Materials

The board of directors has adopted the following materials, which are available on our website www.bpmidstreampartners.com:

- Charter of the Audit Committee of the Board of Directors;
- Corporate Code of Business Conduct and Ethics;
- Financial Code of Ethics; and
- Corporate Governance Guidelines.

Unitholders may also obtain a copy, free of charge, of each of these documents by sending a written request to BP Midstream Partners LP, 501 Westlake Park Boulevard, Houston, Texas 77079. We intend to disclose any amendments to, or waivers from, our Code of Business Conduct and Ethics on our website.

Executive Officers and Directors of Our General Partner

The following table sets forth information for the executive officers and directors of our general partner. Directors hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board. There are no family relationships among any of our directors or executive officers. All of our non-independent directors and all of our executive officers also serve as directors or executives of BP Pipelines or its affiliates.

Name	Age(1)	Position with BP Midstream Partners GP LLC
Robert P. Zinsmeister	63	Director, Chief Executive Officer
Craig W. Coburn(2)	56	Director, Chief Financial Officer
David Kurt(3)	53	Chief Operating Officer
Derek Rush	49	Chief Development Officer
Hans F. Boas	55	Chief Legal Counsel and Secretary
J. Douglas Sparkman	63	Director, Chairman of the Board of Directors
Jack T. Collins(4)	45	Director
Clive Christison	49	Director
Walter Clements	61	Independent Director
Robert Malone	68	Independent Director
Michele F. Joy	65	Independent Director

(1) On February 25, 2021.
(2) Mr. Coburn will retire as Director and Chief Financial Officer effective February 28, 2021.
(3) Mr. Kurt was appointed to the position of Co-Chief Operating Officer effective October 1, 2020. On December 31, 2020, his title changed to Chief Operating Officer.
(4) Mr. Collins was appointed to the position of Director effective October 8, 2020.

Robert P. Zinsmeister was appointed as the Chief Executive Officer of our general partner and member of the board of directors of our general partner in September 2017. Since January 2021, Mr. Zinsmeister has served as M&A Distinguished Advisor for BP's Global M&A organization. From January 2012 to December 2020, Mr. Zinsmeister served as Chief Operating Officer of BP’s Global M&A organization. Mr. Zinsmeister has 21 years of M&A experience, and prior to his current role, his titles and responsibilities included M&A Director Downstream, Corporate, Chemicals and M&A Project Manager. Mr. Zinsmeister has served in a variety of management positions within the BP organization, including Commercial Manager and Engineering Manager of an Upstream business unit, and a variety of engineering roles in corporate, division, and field operations. In addition to his roles at BP, Mr. Zinsmeister is a member of the Advisory Board of Buckthorn Partners, a private equity investment firm investing exclusively in oil field service businesses. Mr. Zinsmeister earned a Bachelor of Science in Petroleum and Natural Gas Engineering, from Pennsylvania State University and an MBA, finance emphasis, from the University of Chicago. In his career Mr. Zinsmeister has personally negotiated three US pipeline transactions, and has overseen all Downstream M&A, including pipelines and midstream, since 2006. We believe that based on Mr. Zinsmeister’s extensive experience in M&A in the energy industry and managerial experience within the BP organization, Mr. Zinsmeister brings important skills and expertise to the board of directors of our general partner.

Craig W. Coburn was appointed as the Chief Financial Officer of our general partner and member of the board of directors of our general partner in September 2017. Since August of 2016, Mr. Coburn has served as Chief Financial Officer for BP America. Prior to such role, from July 2013 to August 2016, Mr. Coburn was Vice President, Technology Commercialization & Venturing (TC&V) for BP. In this role, Mr. Coburn’s primary responsibility was to manage BP’s corporate venture capital portfolio and new investments. Additionally, from January 2006 to August 2016, Mr. Coburn was CFO for BP’s Alternative Energy business which included the Solar, Wind, Biofuels and Emerging Business & Ventures businesses. Prior to holding such roles, Mr. Coburn served in a variety of finance and commercial positions within the BP organization since 1986. Mr. Coburn has over 31 years of oil and gas experience with Amoco and BP, as well as over 20 years of experience working with high tech businesses and renewable energy. He has extensive experience in finance, corporate venturing, technology commercialization, planning and strategy, mergers and acquisitions and business carve-outs. Mr. Coburn has a BS degree in Accountancy from the University of Illinois at Urbana–Champaign and an MBA from the Kellogg School of Management at Northwestern University. We believe that based on Mr. Coburn’s extensive experience in the energy industry and extensive financial knowledge, Mr. Coburn brings important skills and expertise to the board of directors of our general partner. Mr. Coburn elected to retire from his position effective February 28, 2021.

David Kurt was appointed Co-Chief Operating Officer of our general partner in October 2020. On December 31, 2020, his title changed to Chief Operating Officer. Since January 2021, Mr. Kurt has served as Vice President of Terminals & Pipelines for the BP Production & operations organization. From May 2020 until December 2020, Mr. Kurt served as Refinery Manager of the Whiting Refinery, where he was responsible for all aspects of safety, operational and financial performance of the refinery. Mr. Kurt has held various positions at Whiting Refinery, including as Health, Safety, Security and Environment Manager from 2019 to 2020, Production Manager from 2017 to 2019, and Business Improvement Manager from 2015 to 2017. Mr. Kurt joined BP in 1996 and has a BS in Agricultural Engineering and an MBA from Ohio State University.

Derek Rush was appointed Chief Development Officer of our general partner in August 2019. Since January 2021, Mr. Rush has served as Global Logistics & BPMP Senior Finance and Commercial Manager for the BP Customers & products organization. Since August 2018, Mr. Rush has served as a Director for BP Pipelines. From August 2018 to December 2020, Mr. Rush served as Head of Finance for BP US Pipelines and Logistics. From July 2015 to July 2018, Mr. Rush served as Head of Control for BP Downstream, and from April 2013 to July 2015 served as Vice President of BP-Husky Refining LLC. Prior to that, Mr. Rush held a variety of financial and commercial roles in BP. He joined BP in 2005 from PricewaterhouseCoopers, where he was a Director in the financial advisory practice. Mr. Rush has a BS in Biology from the University of Illinois at Urbana-Champaign and a MS in Accountancy from Illinois State University.

Hans F. Boas was appointed as the Chief Legal Counsel and Secretary of our general partner in September 2017. Since February 2017, Mr. Boas has served as Managing Counsel of BP America, Inc., supporting BP’s Treasury functions in the US. From July 2009 to January, 2017, Mr. Boas served as Senior Counsel of BP America, supporting Treasury functions in Houston, Texas. Mr. Boas has over 17 years of experience in the oil and gas industry. Mr. Boas has a BBA, Finance from Texas A&M University and a JD from University of Houston Law Center.

J. Douglas Sparkman became Chairman and member of the board of directors of our general partner in September 2017. Since January 2021, Mr. Sparkman has served as Senior Vice President of BP Solutions for the BP Regions, cities & solutions organization. From October 2014 to December 2020, Mr. Sparkman served as the Chief Operating Officer, Fuels North America. In this role, he was responsible for BP’s North American Downstream—three refineries, USPL, Supply, Sales and Marketing. Prior to this role, Mr. Sparkman was the Strategic Performance Unit leader for the Midwest Fuels Value Chain for BP, which he held since January 2010. Prior to working for BP, Mr. Sparkman served as the Senior Vice President for Transportation and Logistics for Marathon Oil Corporation. Mr. Sparkman has over 38 years of experience in the Downstream business with deep experience in Refining and Midstream operations. We believe that Mr. Sparkman’s substantial experience in various aspects of the energy industry makes him qualified to serve as a member of the board of directors of our general partner.

Jack T. Collins became a member of the board of directors of our general partner in October 2020. Since July 2020, Mr. Collins has served as President of BPX Energy. From December 2014 to July 2020, Mr. Collins served as Senior Vice President and Chief Financial Officer of BPX Energy. Prior to joining BPX Energy in 2014, Mr. Collins held various executive roles in finance and investor relations, including at Denbury Resources, Inc and PostRock Energy Corp. He has more than 20 years’ experience across the energy sector. Mr. Collins has a BA in Economics from the University of Colorado and completed the Advanced Management Program at Harvard Business School.

Clive Christison became a member of the board of directors of our general partner in September 2017. Since January 2021, Mr. Christison has served as Senior Vice President of Fuel Supply and Midstream for the BP Customers & products organization. From September 2015 to December 2020, Mr. Christison served in the role of Senior Vice President Pipelines, Supply & Optimization for Fuels North America. From September 2013 to September 2015 he was the Chief Executive of BP’s Integrated Supply & Trading business for the Americas, responsible for BP’s oil trading and supply activity in the Americas and for crude oil globally. In addition, from September 2008 to September 2013, Mr. Christison also led BP’s oil, gas, chemicals, carbon and finance trading business for the Eastern Hemisphere, covering the Middle East, Southern & East Africa, Australia, India, South East Asia and China. Mr. Christison has 20 years of international experience in Oil, Gas and Power industries, holding a number of senior roles in Supply & Trading, Refining & Marketing and Logistics for Mobil Oil Corporation and BP plc. Mr. Christison is a member of the boards of directors of BP Americas Diversity and Inclusion Council, Commodities Futures Trading Commission (CFTC) Global Markets Advisory Committee, Futures Industry Association, Commodity Markets Council, British American Business Council, Chicago Shakespeare Theatre and the Chicago Urban League. Mr. Christison is a graduate of Edinburgh University with a degree in Chemical Engineering and has an MBA from Warwick Business School. We believe that Mr. Christison’s extensive experience in the energy industry, particularly his experience in supply and trading, makes him qualified to serve as a member of the board of directors of our general partner.

Walter Clements became an independent member of our board of directors, effective upon our listing on the NYSE. Effective January 2019, Mr. Clements was named Associate Dean of Executive Education at University of Notre Dame’s Mendoza College of Business in addition to his role as Teaching Professor of Finance at the college where he has served since August 2012. Previously, from August 2010 to July 2012, Mr. Clements served as a Visiting Lecturer of Finance at Indiana University.

Additionally, Mr. Clements currently consults for new ventures and has 28 years of experience in the energy industry. Mr. Clements has an undergraduate degree in Accounting from Indiana University, an MBA from the University of Chicago, and is a Certified Public Accountant. We believe that Mr. Clements' extensive experience in finance makes him qualified to serve as a member of the board of directors of our general partner.

Robert Malone became an independent member of our board of directors in November 2017. He has served as the Executive Chairman, President and CEO of First Sonora Bancshares, Inc. (a privately-held bank holding company), the holding company for The First National Bank of Sonora (dba Sonora Bank) since 2014. Mr. Malone has also served as the Chairman, President and Chief Executive Officer of Sonora Bank since 2014. He joined First Sonora Bancshares and Sonora Bank in October 2009 as President and Chief Executive Officer. He joined Community Banking following a 35 year career with BP. Prior to his retirement he was an Executive Vice President of BP p.l.c., Chairman and President of BP America and a member of BP's London based Executive Management team that guided the worldwide operations of BP. Mr. Malone has served in a variety of operating, engineering and executive roles with BP's subsidiary companies and he also served as President, CEO and COO of Alyeska Pipeline Service Company, operator of the Trans Alaska Oil Pipeline and as the Chief Executive of the London based BP Shipping Ltd. Mr. Malone currently serves as an independent director of the Halliburton Company, Peabody Energy Company and Teledyne Technologies Incorporated. Mr. Malone earned a BS in Metallurgical Engineering from the University of Texas at El Paso, and was an Alfred P. Sloan Fellow at the Massachusetts Institute of Technology where he received a MS in Management. We believe that Mr. Malone's extensive experience in finance makes him qualified to serve as a member of the board of directors of our general partner.

Michele F. Joy became an independent member of our board of directors in May 2018. She has served as Vice President, Regulatory and Major Projects of the general partner of Shell Midstream Partners ("SHLX") from 2014 to 2017, when she resigned and retired from Shell. From April 2012, Ms. Joy also served as Vice President, SPLC and General Manager of Major Projects and Regulatory for Shell Oil Company. Ms. Joy split her time between her roles at SPLC and time devoted to SHLX's business and affairs. She was responsible for SPLC and SHLX planning and long-term growth, as well as regulatory compliance. Ms. Joy joined SPLC in 2006 as Director of Joint Interests. From 2008 to 2012, she was General Manager, Business Development for SPLC during a period of significant growth. She has also served as a Shell representative on a number of joint ventures, including Colonial, LOOP LLC, Poseidon Pipeline Company LLC and Explorer Pipeline Company. Ms. Joy was a member of the Department of Transportation's Hazardous Liquid Pipeline Safety Advisory Committee and the Association of Oil Pipeline's Economic Regulatory Committee until her retirement. Prior to joining Shell, Ms. Joy served as the General Counsel for the Association of Oil Pipe Lines from 1991 to 2006. In that role, she was involved in the industry's and regulators' joint work to simplify economic regulation at the FERC; improve pipeline safety at DOT (including pipeline integrity and the elimination of outside force damage); and support the EPA's environmental improvements such as ultra-low sulfur diesel implementation. Ms. Joy also served five years as an adjunct professor at Northwestern University's Transportation Institute and spent eight years in private practice focusing on gas and electric regulation and international law. Ms. Joy earned a BA from Carleton College and a JD from American University. We believe that Ms. Joy's extensive experience in finance makes her qualified to serve as a member of the board of directors of our general partner.

Director Independence

As a publicly traded partnership, we qualify for, and are relying on, certain exemptions from the NYSE corporate governance requirements, including:

- the requirement that a majority of the board of directors of our general partner consist of independent directors;
- the requirement that the board of directors of our general partner have a nominating/corporate governance committee that is composed entirely of independent directors; and,
- the requirement that the board of directors of our general partner have a compensation committee that is composed entirely of independent directors.

As a result of these exemptions, our general partner's board of directors is not comprised of a majority of independent directors. Our board of directors does not currently intend to establish a nominating/corporate governance committee or a compensation committee. Accordingly, unitholders do not have the same protections afforded to equity holders of companies that are subject to all of the corporate governance requirements of the NYSE.

We are, however, required to have an audit committee of at least three members, all of whom satisfy the independence and experience standards established by the NYSE and the Exchange Act. The board of directors has affirmatively found Walter Clements, Robert Malone and Michele Joy to be independent under such standards.

Committees of the Board of Directors

The board of directors of our general partner has a standing audit committee and an ad-hoc conflicts committee. We do not have a compensation committee, but rather that the board of directors of our general partner will approve equity grants to eligible directors and employees.

Audit Committee Report

Our general partner has an audit committee composed of at least three members, each of whom meet the independence and experience standards established by the NYSE and the Exchange Act. The audit committee of the board of directors of our general partner assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm.

The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee and our management, as necessary. Mr. Robert Malone, Mr. Walter Clements, and Ms. Michele Joy comprise the members of the audit committee. Each of the members satisfy the definition of audit committee financial expert for purposes of the SEC's rules.

While the audit committee of the board of directors of our general partner oversees the Partnership's financial reporting process on behalf of the board of directors, management has the primary responsibility for the financial statements and the reporting process, including the systems of internal controls.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K. It has also discussed with the independent auditors the matters required by Public Company Accounting Oversight Board ("PCAOB") Auditing Standard 1301, Communications with Audit Committees. Our audit committee has received written disclosures and the letter from the independent accountants required by applicable requirements of the PCAOB regarding the independent accountant's communications with the audit committee concerning independence, and has discussed with the independent accountant the independent accountant's independence.

The audit committee recommended to the Board that the audited financial statements as of and for the year ended December 31, 2020 be included in this report.

Members of the audit committee of the board of directors of BP Midstream Partners GP LLC:
Robert Malone, Chairman
Walter Clements
Michele F. Joy

Conflicts Committee

One or more independent members of the board of directors of our general partner will serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee will determine if the resolution of the conflict of interest is opposed to the interest of the partnership. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including BP Pipelines, and must meet the independence standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. In addition, the members of our conflicts committee may not own any interest in our general partner or its affiliates (other than common units or awards under our LTIP) that is determined by the board of directors of our general partner to have an adverse impact on the ability of such director to act in an independent manner with respect to the matter submitted to the conflicts committee. Any matters approved by the conflicts committee will be conclusively deemed to be approved by us and all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

Our partnership agreement provides that the conflicts committee of the board of directors of our general partner may be comprised of one or more independent directors. For example, if as a result of resignation, disability, death or conflict of interest with respect to a party to a particular transaction, only one independent director is available or qualified to evaluate such transaction, your interests may not be as well served as if the conflicts committee acted with at least two independent directors.

A single-member conflicts committee would not have the benefit of discussion with, and input from, other independent directors.

Board Leadership Structure

The board of directors of our general partner has no policy with respect to the separation of the offices of chairman of the board of directors and chief executive officer. Instead, that relationship is defined and governed by the amended and restated limited liability company agreement of our general partner, which permits the same person to hold both offices. Directors of the board of directors of our general partner are designated or elected by BP Holdco. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our corporate governance guidelines provide that the board of directors of our general partner is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility is largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our independent registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies.

Item 11. EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing our business. We are managed and operated by our general partner. All of the executive officers of our general partner are employed and compensated by BP Pipelines or its affiliates. They have responsibilities to both us and BP Pipelines and its affiliates, and we expect that they are allocating their time between managing our business and managing the business of BP Pipelines.

The responsibility and authority for compensation-related decisions for our executive officers reside with BP Pipelines or its affiliates. Any such compensation decisions are not subject to any approvals by the board of directors of our general partner or any committees thereof. However, all determinations with respect to awards that may be made to our executive officers, key employees, and independent directors under the LTIP are made by the board of directors of our general partner.

Except with respect to awards that have been granted under the LTIP, our executive officers do not currently receive separate amounts of compensation in relation to the services they provide to us. We reimburse BP Pipelines for compensation related expenses attributable to the portion of each executive officer’s time dedicated to providing services to us. Although we bear an allocated portion of BP Pipelines’ costs of providing compensation and benefits to employees who serve as executive officers of our general partner, we have no control over such costs and do not establish or direct the compensation policies or practices of BP Pipelines.

Our general partner does not have a compensation committee and does not currently expect to put one in place.

Summary Compensation Table

The following summarizes the total compensation paid to our named executive officers by BPMP for their services in relation to our business in 2020, 2019 and 2018.

Name and Principal Position[1]	Year	Salary	Stock Awards	Bonus	Stock Options	Non-Equity Incentive Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
Robert P. Zinsmeister, Chief Executive Officer and Director	2020	—	—	—	—	—	—	—	—
	2019	—	—	—	—	—	—	—	—
	2018	—	—	—	—	—	—	—	—
Craig W. Coburn, Chief Financial Officer and Director	2020	—	—	—	—	—	—	—	—
	2019	—	—	—	—	—	—	—	—
	2018	—	—	—	—	—	—	—	—
David Kurt, Chief Operating Officer[2]	2020	—	—	—	—	—	—	—	—
Gerald J. Maret, Former Chief Operating Officer[3]	2020	—	—	—	—	—	—	—	—
	2019	—	—	—	—	—	—	—	—
	2018	—	—	—	—	—	—	—	—
Derek Rush, Chief Development Officer[4]	2020	—	—	—	—	—	—	—	—
	2019	—	—	—	—	—	—	—	—
Hans F. Boas, Chief Legal Counsel and Secretary	2020	—	—	—	—	—	—	—	—
	2019	—	—	—	—	—	—	—	—
	2018	—	—	—	—	—	—	—	—

(1) Messrs. Zinsmeister, Coburn, Kurt, Rush and Boas devote, and prior to his retirement, Mr. Maret devoted, a portion of their overall working time to our business. Except for the fixed administrative fee we paid to BP Pipelines under the omnibus agreement, we did not pay or reimburse any compensation amounts to or for our named executive officers in 2020, 2019 or 2018.
(2) Mr. Kurt was appointed to the position of Co-Chief Operating Officer, effective October 1, 2020. On December 31, 2020, his title changed to Chief Operating Officer.
(3) Mr. Maret retired from his position as Chief Operating Officer, effective December 31, 2020.
(4) Mr. Rush was appointed to the position of Chief Development Officer, effective August 6, 2019.

Narrative Disclosure to Executive Compensation

Compensation by BP

Our named executive officers receive compensation in the form of base salaries, annual cash incentive awards, long-term equity incentive awards and participation in various employee benefit plans and arrangements, including broad based and supplemental defined contribution and defined benefit retirement plans. In addition, although our executive officers have not entered into employment agreements with BP, they have end of employment arrangements with BP under which they would receive separation payments and benefits from BP based on termination at the employer’s initiative or on mutually agreed terms. In the future, BP may provide different or additional compensation components, benefits, or perquisites to our named executive officers.

The following sets forth a more detailed explanation of the elements of compensation that our named executive officers receive.

Base Compensation

Our named executive officers earn a base salary for their services to BP and its affiliates, which amounts are paid by BP or its affiliates other than us. We incur only a fixed expense per month under the omnibus agreement with respect to the compensation paid by BP to each of our named executive officers.

Annual Cash Bonus Payments

Our named executive officers are eligible to earn cash payments from BP under BP’s annual incentive bonus program and other discretionary bonuses that may be awarded by BP. Any bonus payments earned by the named executive officers will be paid by BP and will be determined solely by BP without input from us or our general partner or its board of directors. The amount of any bonus payment made by BP will not result in changes to the contractually fixed fee for executive management services that we pay to BP under the omnibus agreement.

Share-Based Compensation

The incentive compensation programs in which our named executive officers participate primarily consist of share awards, restricted share awards or cash awards (any of which may be a performance award). Conditional awards of BP shares are made under the terms of the Share Value Plan on a selective basis to senior personnel each year. The extent to which the awards vest is determined over a three-year performance period. The award is based on the business performance of BP plus an adjustment using an individual performance factor. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. None of the awards result in beneficial ownership until the shares are delivered. Shares are awarded subject to a three-year vesting period.

Long-Term Equity-Based Incentive Compensation

BP maintains a long-term incentive program pursuant to which it grants equity-based awards in BP p.l.c. to certain of its executives and employees. Our named executive officers may receive awards under BP's equity incentive plan from time to time as may be determined by BP (if applicable). The amount of any long-term incentive compensation made by BP will not result in changes to the contractually fixed fee for executive management services that we will pay to BP under the omnibus agreement.

Retirement, Health, Welfare and Additional Benefits

Our named executive officers are eligible to participate in the employee benefit plans and programs that BP offers to its employees, subject to the terms and eligibility requirements of those plans. Our named executive officers are also eligible to participate in BP's tax-qualified defined contribution and defined benefit retirement plans, and post retiree medical plans, to the same extent as all other BP employees. BP also has certain supplemental retirement plans in which its executives and key employees participate.

Grants of Plan-Based Awards

We did not grant any equity awards to our named executive officers during 2020.

		Estimated future payouts under non-equity incentive plan awards			Estimated future payouts under equity incentive plan awards						
Name	Grant date	Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	All other unit awards: Number of units (#)	All other unit awards: Number of securities underlying options (#)	Exercise or base price of option awards ($/Sh)	Grant date fair value of unit and option awards
Robert P. Zinsmeister	—	—	—	—	—	—	—	—	—	—	—
Craig W. Coburn	—	—	—	—	—	—	—	—	—	—	—
David Kurt	—	—	—	—	—	—	—	—	—	—	—
Gerald J. Maret	—	—	—	—	—	—	—	—	—	—	—
Derek Rush	—	—	—	—	—	—	—	—	—	—	—
Hans F. Boas	—	—	—	—	—	—	—	—	—	—	—

Outstanding Equity Awards at Fiscal Year End

We have not granted, and none of our named executive officers have received any grants of, unit or unit-based awards and no such awards were outstanding as of December 31, 2020.

Name	Option Awards					Unit Awards			
	Number of securities underlying unexercised options (#) exercisable	Number of securities underlying unexercised options (#) unexercisable	Equity incentive plan awards: number of securities underlying unexercised unearned options (#)	Option exercise price ($)	Option expiration date	Number of units that have not vested (#)	Market value of units that have not vested (#)	Equity incentive plan awards: number of unearned units or other rights that have not vested (#)	Equity incentive plan awards: market or payout value of unearned units or other rights that have not vested ($)
Robert P. Zinsmeister	—	—	—	—	—	—	—	—	—
Craig W. Coburn	—	—	—	—	—	—	—	—	—
David Kurt	—	—	—	—	—	—	—	—	—
Gerald J. Maret	—	—	—	—	—	—	—	—	—
Derek Rush	—	—	—	—	—	—	—	—	—
Hans F. Boas	—	—	—	—	—	—	—	—	—

Option Exercises and Stock Vested

We have not granted, and none of our named executive officers have received any grants of, units or unit-based awards. Hence, no such awards were exercised or vested during 2020.

Name	Option Awards		Unit Awards	
	Number of units acquired on exercise (#)	Value realized on exercise ($)	Number of units acquired on vesting (#)	Value realized on vesting ($)
Robert P. Zinsmeister	—	—	—	—
Craig W. Coburn	—	—	—	—
David Kurt	—	—	—	—
Gerald J. Maret	—	—	—	—
Derek Rush	—	—	—	—
Hans F. Boas	—	—	—	—

Pension Benefits

We do not have any plan that provides for payments or other benefits at, following, or in connection with retirement.

Name	Plan Name	Number of Years Credited Service(#)	Present Value of Accumulated Benefit($)	Payments During Last Fiscal Year($)
Robert P. Zinsmeister	—	—	—	—
Craig W. Coburn	—	—	—	—
David Kurt	—	—	—	—
Gerald J. Maret	—	—	—	—
Derek Rush	—	—	—	—
Hans F. Boas	—	—	—	—

Nonqualified Deferred Compensation

We do not have any plan that provides for the deferral of compensation on a basis that is not tax-qualified.

Name	Beginning Balance($)	Executive Contribution in Last Fiscal Year($)	Registrant Contribution in Last Fiscal Year($)	Aggregate Earnings in Last Fiscal Year($)	Aggregate Withdrawals/Distributions($)	Aggregate Balance at Last Fiscal Year-End(4)($)
Robert P. Zinsmeister	—	—	—	—	—	—
Craig W. Coburn	—	—	—	—	—	—
David Kurt	—	—	—	—	—	—
Gerald J. Maret	—	—	—	—	—	—
Derek Rush	—	—	—	—	—	—
Hans F. Boas	—	—	—	—	—	—

Potential Payments upon Termination or Change-in-Control

Our named executive officers are covered by standard BP severance arrangements. The nature and level of these arrangements vary by job grade and service completed. The maximum payment does not exceed twice base salary plus outplacement support and other non-cash benefits.

Director Compensation

The executive officers or employees of our general partner or of BP who also serve as directors of our general partner do not receive any additional compensation from us for their service as a director of our general partner. Directors of our general partner who are not also officers or employees of BP ("non-employee director") will receive compensation for services on our general partner's board of directors and committees thereof. We currently pay such directors a cash retainer of $75,000. We also currently pay the chair of the audit committee and the chair of the conflicts committee, as applicable, an additional cash retainer of $20,000. We also award an annual equity-based grant under the LTIP. Non-employee directors are reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors and committee meetings.

For 2020, each non-employee director received an award of 5,346 phantom units under the LTIP valued at approximately $75,004. To align awards with our Parent, this grant occurred on February 24, 2020.

The phantom units vest in full on the first anniversary of the date of grant but are not settled until the second anniversary of grant. Each member of the board of directors of our general partner will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

Non-Employee Director Compensation Table

The following summarizes the compensation for our non-employee directors for 2020.

Name	Fee Earned or Paid in Cash	Unit Awards(1)	Option Awards	Non-Equity Inventive Plan Compensation	Non-Qualified Compensation	Deferred Earnings	All Other Compensation	Total
Walter Clements	$ 75,000	$ 75,004	$ —	$ —	$ —	$ —	$ —	$ 150,004
Robert Malone	95,000	75,004	—	—	—	—	—	170,004
Michele F. Joy	75,000	75,004	—	—	—	—	—	150,004

(1) Amounts reported in this column reflect the aggregate grant date fair value of the phantom units, computed in accordance with FASB ASC Topic 718, determined without regard to forfeitures. For more information, refer to Note 15 - *Unit-Based Compensation* in the Notes to Consolidated Financial Statements. As of December 31, 2020, there were a total of 16,038 phantom units outstanding under the LTIP, of which Mr. Clement, Mr. Malone and Ms. Joy each held 5,346.

Pay Ratio Disclosure

We do not have any employees. The officers and all other personnel necessary for our business are employed and compensated by BP, subject to the administrative services fee in accordance with the terms of the omnibus agreement and our operating agreements. Therefore we are unable to provide an estimate of the relationship of the median of the annual total compensation of our employees and the annual total compensation of our chief executive officer.

Compensation Committee Report

We do not have a Compensation Committee. Accordingly, the Compensation Committee Report required by Item 407(e)(5) of Regulation S-K is given by the board of directors of our general partner. The board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis presented above with management and, based on such review and discussions, the board has approved the inclusion of the Compensation Discussion and Analysis in this Annual Report on Form 10-K.

Members of the board of directors of BP Midstream Partners GP LLC:
J. Douglas Sparkman, Chairman
Robert P. Zinsmeister
Craig W. Coburn
Jack T. Collins
Clive Christison
Walter Clements

Robert Malone
Michele F. Joy

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth the beneficial ownership of common units of BP Midstream Partners LP held by beneficial owners of 5% or more of such units, by each director and named executive officer of our general partner and by the directors and executive officers of our general partner as a group. As discussed in Note 17 - *Subsequent Events* in the Notes to Consolidated Financial Statements, on February 12, 2021, all of our subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated. The percentage of units beneficially owned is based on 104,778,502 common units outstanding.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
BP Midstream Partners Holdings LLC(2)	56,956,712	54.4 %
Tortoise Capital Advisors, L.L.C.(3) 5100 W 115th Place Leawood, KS 66211	5,270,137	5.0 %
Robert P. Zinsmeister	5,555	*
Craig W. Coburn	5,500	*
Jack T. Collins(4)	—	—
David Kurt(5)	—	—
Gerald J. Maret(6)	2,500	*
Brian D. Smith(7)	—	—
Derek Rush	—	—
Hans F. Boas	—	—
J. Douglas Sparkman	5,555	*
Clive Christison	2,500	*
Walter Clements(8)	10,143	*
Robert Malone(8)	9,921	*
Michele F. Joy(8)	7,368	*
Directors and executive officers as a group (13 persons)	49,042	*

(*) Indicates beneficial ownership of less than 1%.
(1) The address for all beneficial owners in this table is 501 Westlake Park Boulevard, Houston, Texas 77079.
(2) BP Holdco is a wholly owned subsidiary of BP Pipelines (North America) Inc. and owns the common units presented above. BP Pipelines (North America) Inc. may be deemed to beneficially own the units held by BP Holdco.
(3) Based solely on a Schedule 13G/A filed by Tortoise Capital Advisors, L.L.C. on February 12, 2021.
(4) Mr. Collins was appointed to the position of Director effective October 8, 2020.
(5) Mr. Kurt was appointed to the position of Co-Chief Operating Officer effective October 1, 2020. On December 31, 2020, his title changed to Chief Operating Officer.
(6) Mr. Maret elected to retire from his position as Chief Operating Officer effective December 31, 2020.
(7) Mr. Smith elected to retire from his position as a director of the general partner, effective October 8, 2020.
(8) Represents unit-based awards granted under the LTIP and are subject to the terms thereunder.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth information about all existing equity compensation plans as of December 31, 2020.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (1)
	(a)	(b)	(c)
Equity compensation plans approved by security holders	16,038 (2)	—	5,458,801
Equity compensation plans not approved by security holders	—	—	—
Total	16,038	—	5,458,801

(1) The amounts shown represents common units available under the LTIP as of December 31, 2020.
(2) Represents unit-based awards granted under the LTIP and are subject to the terms thereunder.

Item 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS, AND DIRECTOR INDEPENDENCE

As of February 24, 2021, BP Holdco owns 56,956,712 common units representing approximately an aggregate 54.4% limited partner interest in us (excluding the incentive distribution rights, which cannot be expressed as a fixed percentage), and owns and controls our general partner. BP Holdco also appoints all of the directors of our general partner, which owns a non-economic general partner interest in us and owns the incentive distribution rights.

The terms of the transactions and agreements disclosed in this section were determined by and among affiliated entities and, consequently, are not the result of arm's length negotiations. These terms are not necessarily at least as favorable to the parties to these transactions and agreements as the terms that could have been obtained from unaffiliated third parties.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the ongoing operation and any liquidation of the Partnership.

Operational Stage

Distributions of cash available for distribution to our general partner and its affiliates	We make cash distributions to our unitholders, including affiliates of our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner is entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level. Assuming we have sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our outstanding common units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $59.8 million on their units.
Payments to our general partner and its affiliates	BP Pipelines provides customary operating, management and general administrative services to us. Our general partner shall reimburse BP Pipelines and its affiliates pursuant to the Omnibus Agreement as described below for its direct expenses incurred on behalf of us and a proportionate amount of its and their indirect expenses incurred on behalf of us, including, but not limited to, compensation expenses. Our general partner does not receive a management fee or other compensation for its management of our partnership, but we do reimburse our general partner and its affiliates for all direct and indirect expenses they incur and payments they make on our behalf, including payments made to BP Pipelines for customary management and general administrative services. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, benefits, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us.

Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements Governing the Formation Transactions

We entered into various documents and agreements with BP, as described in detail below. These agreements are not the result of arm's-length negotiations. However, we believe that these fees are substantially equivalent to the fees that we would expect to charge others or to be charged by others for similar services.

Omnibus Agreement

We have an omnibus agreement in place with BP Pipelines and our general partner that addresses the following matters:

- our payment of an annual administrative fee of initially $13.6 million, for the provision of general and administrative services and, in addition, to reimburse personnel and other costs related to the direct operation, management and maintenance of the assets by BP Pipelines and its affiliates;
- our obligation to reimburse BP Pipelines and its affiliates for personnel costs related to the direct operation, management, maintenance and repair of the assets incurred by BP Pipelines or its affiliates on our behalf;
- our obligation to reimburse BP Pipelines and its affiliates for services and certain direct or allocated costs and expenses incurred by BP Pipelines or its affiliates on our behalf;
- BP Pipelines' obligation to indemnify us for certain environmental and other liabilities, and our obligation to indemnify BP Pipelines for certain environmental and other liabilities related to our assets to the extent BP Pipelines is not required to indemnify us;
- the granting of a license from BP America Inc. to us with respect to use of certain BP trademarks and trade names; and
- BP Pipelines granting to us of a ROFO with respect to the Subject Assets.

So long as BP Pipelines indirectly controls our general partner, the omnibus agreement will remain in full force and effect. If BP Pipelines or its successor ceases to directly or indirectly control our general partner, either party may terminate the omnibus agreement, *provided* that the indemnification obligations will remain in full force and effect in accordance with their terms.

Payment of Administrative Fee and Reimbursement of Expenses. We paid BP Pipelines an administrative fee of initially $13.6 million annually (payable in equal monthly installments), to reimburse BP Pipelines and its affiliates for the provision of certain general and administrative services for our benefit, including services related to the following areas: executive management services; financial management and administrative services (such as treasury and accounting); information technology services; legal services; health, safety and environmental services; land and real property management services; human resources services; procurement services; corporate engineering services; business development services; investor relations, communications and external affairs; insurance administration and tax related services.

Under this agreement, we have agreed to also reimburse BP Pipelines and its affiliates for all other direct or allocated costs and expenses incurred by BP Pipelines in providing these services to us, including personnel costs related to the direct operation, management, maintenance and repair of the assets. This reimbursement is in addition to our reimbursement of our general partner and its affiliates for certain costs and expenses incurred on our behalf for managing and controlling our business and operations as required by our partnership agreement.

The fee was adjusted to $15.2 million per year, payable in equal monthly installments, beginning on January 1, 2020. During the second quarter of 2020, our Parent agreed to adjust the fee payable under the Omnibus Agreement back to the 2019 annual fee, beginning in the second quarter, prorated for the remainder of 2020 due to the ongoing economic effects of the global COVID-19 pandemic. This resulted in a 2020 annual fee of $14.0 million. The annual fee was adjusted to $15.5 million per year, payable in equal monthly installments, beginning on January 1, 2021.

Our general partner, in good faith, may adjust the administrative fee to reflect, among others, any change in the level or complexity of our operations, a change in the scope or cost of services provided to us, inflation or a change in law or other regulatory requirements, the contribution, acquisition or disposition of our assets or any material change in our operation activities.

Environmental Indemnification by BP Pipelines. Under the omnibus agreement, BP Pipelines will indemnify us for losses incurred by us as a result of violations of environmental laws and environmental remediation or corrective action that is required by environmental laws resulting or arising from releases occurring during the ownership or operation of the assets contributed to us by BP Pipelines in connection with our IPO, in each case to the extent (i) such violation occurred on or prior to the closing our IPO under laws in existence prior to the closing of our IPO and (ii) not identified in a voluntary audit or investigation undertaken outside the ordinary course of business by us. BP Pipelines will also indemnify us for Scheduled Environmental Matters related to our assets. Except for Scheduled Environmental Matters, BP Pipelines will not be obligated to indemnify us for any environmental losses unless BP Pipelines is notified of such losses prior to the third anniversary of the closing of our IPO. Furthermore, except for Scheduled Environmental Matters, BP Pipelines will not be obligated to indemnify us until our aggregate indemnifiable losses exceed a $0.5 million deductible (and then BP Pipelines will only be obligated to indemnify us for amounts in excess of such deductible) and such indemnity is capped at $15.0 million (including indemnity obligations for all other environmental, and certain title and litigation claims).

Other Indemnifications by BP Pipelines. BP Pipelines also indemnifies us for the following, to the extent not covered by the above-described environmental indemnity:

- events and conditions associated with BP Pipelines' retained assets, whether before or after the IPO, except to the extent caused by our act or omission after the closing;
- the failure of BP Pipelines to have obtained title or any consent or approval necessary for the direct or indirect conveyance, contribution or transfer to us or our applicable subsidiaries of pipeline and related assets or interests (other than environmental and title, rights of way, consents, licenses, permits or approvals addressed in the other indemnities described above), in each case to the extent BP Pipelines is notified of such matters prior to the first anniversary of the closing of the IPO and subject to an aggregate deductible of $0.5 million;
- any litigation matters attributable to the ownership or operation of the assets contributed to us in connection with the IPO, including the matters pending at the closing of the offering and identified on a schedule to the omnibus agreement, to the extent BP Pipelines is notified of matters that are not listed on such schedule prior to the first anniversary of the closing of the IPO and subject to an aggregate deductible of $0.5 million for such unlisted matters; and
- for a period of time immediately following the closing of the IPO equal to the applicable statute of limitations *plus* 60 days, all tax liabilities attributable to the ownership or the operation of the assets contributed to us in connection with the IPO and arising prior to the closing of the IPO and any such tax liabilities that resulted from the formation of our general partner and us from the consummation of the transactions contemplated by our contribution agreement.

Limitations on Indemnification by BP Pipelines. BP Pipelines’ indemnity obligation for tax liabilities and liabilities associated with BP Pipelines’ retained assets is not subject to a cap. BP Pipelines’ indemnity obligation for conveyance, contribution or transfer of the applicable membership interest or other equity interest to us is capped at BP Pipelines’ net proceeds of the IPO without any deductible. Scheduled Environmental Matters are subject to a cap of $25 million without any deductible, all other indemnity obligations of BP Pipelines under the omnibus agreement (including indemnity obligations for all other environmental, title and litigation claims) are capped at $15 million, and many are subject to a deductible as described above.

Indemnification by Us. We have agreed to indemnify BP Pipelines for events and conditions associated with the ownership, management or operation of our assets, whether related to the period before or after the IPO closing date (including any violation of or any non-compliance with or liability under environmental laws (other than any liabilities for which BP Pipelines is specifically required to indemnify us as described above)). We have also agreed to indemnify BP Pipelines for any losses arising from the performance of BP Pipelines in providing general and administrative services and operating personnel services to us, except to the extent caused by the gross negligence or willful misconduct of BP Pipelines or the personnel providing such services. There is no deductible or limit on the amount for which we will indemnify BP Pipelines under the omnibus agreement.

License of Trademarks. BP America Inc. has granted us a nontransferable, nonexclusive, royalty-free worldwide right and license to use certain trademarks and tradenames owned by BP.

ROFO. BP Pipelines has agreed and has caused its affiliates to agree that if, at any time prior to the earlier of the seventh anniversary of the closing of the IPO and the date on which BP Pipelines or its affiliates cease to control our general partner, BP Pipelines or any of its affiliates decide to attempt to sell (other than to another affiliate of BP Pipelines) the Subject Assets, BP Pipelines or its affiliate will notify us of its desire to sell such Subject Assets and, prior to selling such Subject Assets to a third party, will allow us 45 days from such notice to make a binding written offer regarding the such Subject Assets. Following receipt of any such offer, BP Pipelines or its affiliate will negotiate with us exclusively and in good faith for a period of 60 days in order to give us an opportunity to enter into definitive agreements for the purchase and sale of such Subject Assets on terms that are mutually acceptable to BP Pipelines or its affiliate and us. If (i) we do not deliver a binding written offer regarding such Subject Assets within 45 days of receiving notice of BP Pipelines or its affiliates' desire to sell such Subject Assets, or (ii) if we and BP Pipelines or its affiliate have not entered into a letter of intent or a definitive purchase and sale agreement with respect to such Subject Assets within such 60-day negotiation period, then BP Pipelines or its affiliate may enter into a definitive transfer agreement with any third party with respect to such Subject Assets on terms and conditions that are acceptable to BP Pipelines or its affiliate and such third party.

Termination. The omnibus agreement, except for the indemnification provisions, will terminate by written agreement of all the parties thereto or by BP Pipelines or us immediately at such time as BP Pipelines ceases to indirectly control our general partner.

Interest Purchase Agreement

On October 1, 2018, the Partnership entered into the Interest Purchase Agreement with BP Products, BP Offshore, and BP Pipelines to acquire (i) an additional 45.0% interest in Mardi Gras from BP Pipelines, (ii) a 25.0% interest in KM Phoenix from BP Products, and (iii) a 22.7% interest in Ursa from BP Offshore in exchange for aggregate consideration of $468.0 million, funded with borrowings under the Partnership's revolving credit facility.

Revolving Credit Facility

We entered into a unsecured revolving credit facility with an affiliate of BP. The credit facility has a borrowing capacity of $600.0 million. The credit facility provides for certain covenants, including the requirement to maintain a consolidated leverage ratio not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. In addition, the limited liability company agreement of our general partner requires the approval of BP Holdco prior to the incurrence of any indebtedness that would cause our ratio of total indebtedness to consolidated EBITDA (as defined in the credit facility) to exceed 4.5 to 1.0.

The credit facility also contains customary events of default, such as (i) nonpayment of principal when due, (ii) nonpayment of interest, fees or other amounts, (iii) breach of covenants, (iv) misrepresentation, (v) cross-payment default and cross-acceleration (in each case, to indebtedness in excess of $75 million) and (vi) insolvency. Additionally, our revolving credit facility limits our ability to, among other things: (i) incur or guarantee additional debt, (ii) redeem or repurchase units or make distributions under certain circumstances; and (iii) incur certain liens or permit them to exist. Indebtedness under this facility bears interest at the 3 month LIBOR plus 0.85%. This facility includes customary fees, including a commitment fee of 0.1% and a utilisation fee of 0.2%. The credit facility is subject to definitive documentation, closing requirements and certain other conditions.

On February 24, 2020, the Partnership entered into a $468.0 million Term Loan Facility Agreement ("term loan") with an affiliate of BP. On March 13, 2020, proceeds were used to repay outstanding borrowings under the existing credit facility. The term loan has a final repayment date of February 24, 2025, and provides for certain covenants, including the requirement to maintain a consolidated leverage ratio, which is calculated as total indebtedness to consolidated EBITDA, not to exceed 5.0 to 1.0, subject to a temporary increase in such ratio to 5.5 to 1.0 in connection with certain material acquisitions. Simultaneous with this transaction, we entered into a First Amendment to Short Term Credit Facility Agreement ("First Amendment") whereby the lender added a provision that indebtedness under both the term loan and credit facility shall not exceed $600.0 million. All other terms of the credit facility remain the same.

Transportation Revenues

During the year ended December 31, 2020, we recognized transportation revenues of $112.8 million related to volumes transported on the Wholly Owned Assets from companies affiliated with BP.

These transactions were conducted at posted tariff rates or prices that we believe approximate market rates. These amounts do not include revenues from Mars, Ursa, KM Phoenix or the Mardi Gras Joint Ventures. The transportation revenues recognized during these periods include FLA amounts settled with BP. On October 30, 2017, we entered into an agreement with an affiliate of BP governing the sale of crude oil acquired as FLA under the applicable crude oil tariffs whereby the partnership will continue to settle its FLA collected volumes with such affiliate of BP.

Throughput and Deficiency Agreements

During the year ended December 31, 2020, we recognized transportation revenues of $112.8 million and deficiency revenue of $13.2 million for a total of $126.0 million from the throughput and deficiency agreements with companies affiliated with BP.

We have commercial agreements with BP Products that include minimum volume commitments and that initially support substantially all of our aggregate revenue on BP2, River Rouge and Diamondback. Under these fee-based agreements, we provide transportation services to BP Products, and BP Products has committed to pay us for minimum monthly volumes of crude oil, refined products and diluent, regardless of whether such volumes are physically shipped by BP Products through our pipelines during the term of the agreements. Please read "Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements."

Other Agreements

BP2 OpCo and River Rouge OpCo have entered into sublease agreements with BP Pipelines with respect to locations where the IPO Contributed Assets are located within BP Pipelines' lease premises. The sublease agreements provide the right for the assets to be located on the premises and define certain services provided by BP Pipelines related to the assets on the premises. These agreements have a term of 50 years.

Procedures for Review, Approval or Ratification of Transactions with Related Parties

The board of directors of our general partner has adopted policies for the review, approval and ratification of transactions with related persons. The board has also adopted a written code of business conduct and ethics, under which a director will be expected to bring to the attention of the chief executive officer or the board any conflict or potential conflict of interest that may arise between the director in his or her personal capacity or any affiliate of the director in his or her personal capacity, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the board of directors of our general partner in accordance with the provisions of our partnership agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under our partnership agreement.

Our adoption of our code of business conduct requires executive officers to avoid personal conflicts of interest unless approved by the board of directors of our general partner.

There were no related person transactions during 2020 which were required to be reported in "Certain Relationships and Related Transactions, and Director Independence" where the procedures described above did not require review, approval or ratification or where these procedures were not followed.

Director Independence

Rather than adopting categorical standards, the board of directors of our general partner assesses director independence on a case-by-case basis, in each case consistent with applicable legal requirements and the listing standards of the NYSE. After reviewing all relationships each director has with us, including the nature and extent of (i) any business, employment or familial relationships between us and each director, as well as (ii) any significant charitable contributions we make to organizations where our directors serve as board members or executive officers, the board of directors of our general partner has affirmatively determined that Walter Clements, Robert Malone, and Michele Joy have no material relationships with us and are independent as defined by the current listing standards of the NYSE.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table presents fees for professional services performed by independent registered public accounting firm, Deloitte & Touche LLP for 2020 and 2019, respectively.

Fees (millions of dollars)	2020	2019
Audit fees [(1)]	$ 1.1	$ 1.1
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$ 1.1	$ 1.1

(1) Audit fees represent amounts billed for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements, and (iii) services provided in connection with regulatory filings.

The Audit Committee has adopted a pre-approval policy that provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided to the Partnership. All of the fees in the table above were approved in accordance with this policy. The policy (a) identifies the guiding principles that must be considered by the Audit Committee in approving services to ensure that Deloitte & Touche LLP's independence is not impaired; (b) describes the audit, audit-related, tax and other services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services. Under the policy, all services to be provided by Deloitte & Touche LLP must be pre-approved by the Audit Committee. The Audit Committee has delegated authority to approve permitted services to the Audit Committee's Chair. Such approval must be reported to the entire Audit Committee at the next scheduled Audit Committee meeting.

The audit committee has sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and, as outlined above, (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee and our management.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

1. Financial Statements and Supplementary Data

The financial statements and supplementary information listed in the Index to Consolidated Financial Statements, which appears in Part II, Item 8, are filed as part of this Annual Report.

2. Financial Statement Schedules

The following financial statements are included pursuant to Rule 3-09 of Regulation S-X (17 CFR 210.3-09):

Mars Oil Pipeline Company, LLC	Financial Statements as of December 31, 2020 and 2019 and for the fiscal years ended December 31, 2020, 2019 and 2018.

All other financial statement schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the consolidated financial statements or the notes to consolidated financial statements.

3. Exhibits

The exhibits listed in the Index to Exhibits are filed as part of this Annual Report.

BP MIDSTREAM PARTNERS LP
INDEX TO EXHIBITS

Exhibit No.	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
3.1	Certificate of Limited Partnership of BP Midstream Partners LP	S-1	3.1	9/11/2017	333-220407		
3.2	Amended and Restated Agreement of Limited Partnership of BP Midstream Partners LP dated October 30, 2017.	10-Q	3.2	12/6/2017	001-38260		
3.3	Certificate of Formation of BP Midstream Partners GP LLC	S-1	3.3	9/11/2017	333-220407		
3.4	First Amended and Restated Limited Liability Company Agreement of BP Midstream Partners GP LLC	S-1	3.4	9/11/2017	333-220407		
4.1	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	10-K	4.1	2/27/2020	001-38260		
10.1	Contribution, Assignment and Assumption Agreement dated, October 30, 2017 by and among BP Pipelines (North America) Inc., BP Midstream Partners GP LLC, BP Midstream Partners LP, BP Midstream Partners Holdings LLC, and The Standard Oil Company.	8-K	10.1	11/1/2017	001-38260		
10.2	Omnibus Agreement dated October 30, 2017 by and among BP Pipelines (North America) Inc., BP Midstream Partners LP, BP Midstream Partners GP LLC, and solely for the purposes of Articles 4 and 6, BP America Inc.	8-K	10.2	11/1/2017	001-38260		
10.3	BP Midstream Partners LP Short Term Credit Facility Agreement, dated as of October 30, 2017, between BP Midstream Partners LP and North America Funding Company	8-K	10.3	11/1/2017	001-38260		
10.4*	Form of Indemnification Agreement	S-1/A	10.6	9/25/2017	333-220407		
10.5	BP Two Pipeline Company LLC Throughput and Deficiency Agreement, dated October 30, 2017, between BP Midstream Partners LP and BP Products North America Inc.	8-K	10.4	11/1/2017	001-38260		
10.6	BP River Rouge Pipeline Company LLC Throughput and Deficiency Agreement, dated October 30, 2017, between BP Midstream Partners LP and BP Products North America Inc.	8-K	10.5	11/1/2017	001-38260		
10.7	BP D-B Pipeline Company LLC Throughput and Deficiency Agreement, dated October 30, 2017, between BP Midstream Partners LP and BP Products North America Inc.	8-K	10.6	11/1/2017	001-38260		
10.8	Second Amended and Restated Limited Liability Company Agreement of Mardi Gras Transportation System Company LLC dated October 30, 2017 by and among BP Midstream Partners LP, BP Pipelines (North America) Inc. and The Standard Oil Company	8-K	10.7	11/1/2017	001-38260		
10.9*	BP Midstream Partners LP 2017 Long-Term Incentive Plan	S-8	4.4	10/30/2017	333-221213		
10.10*	Form of Phantom Award Agreement (Non-Employee Directors)	S-8	4.5	10/30/2017	333-221213		
10.11*	Form of Phantom Award Agreement (Non-Employee Directors Deferred Settlement)	S-8	4.6	10/30/2017	333-221213		
10.12	Term Loan Facility Agreement, dated February 24, 2020, between BP Midstream Partners LP and North America Funding Company	10-K	10.12	2/27/2020	001-38260		
10.13	First Amendment To Short Term Credit Facility Agreement, dated February 24, 2020, between BP Midstream Partners LP and North America Funding Company	10-K	10.13	2/27/2020	001-38260		
10.14	BP Two Pipeline Company LLC Throughput and Deficiency Agreement, dated November 3, 2020, between BP Midstream Partners LP and BP Products North America Inc.	10-Q	10.1	11/5/2020	001-38260		
10.15	BP River Rouge Pipeline Company LLC Throughput and Deficiency Agreement, dated November 3, 2020, between BP Midstream Partners LP and BP Products North America Inc.	10-Q	10.2	11/5/2020	001-38260		
10.16	BP D-B Pipeline Company LLC Throughput and Deficiency Agreement, dated November 3, 2020, between BP Midstream Partners LP and BP Products North America Inc.	10-Q	10.3	11/5/2020	001-38260		
21	List of Subsidiaries of BP Midstream Partners LP					X	
23.1	Consent of Deloitte & Touche LLP, independent registered public accounting firm					X	
23.2	Consent of Ernst & Young LLP, independent auditors					X	
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X	
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32**	Certifications pursuant to 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X

99.1	Mars Oil Pipeline Company, LLC Financial Statements as of December 31, 2020 and 2019 and for the fiscal years ended December 31, 2020, 2019 and 2018.	X
101	The following financial information from BP Midstream Partners LP's Annual Report on Form 10-K for the fiscal year ended December 31, 2020, formatted in iXBRL (Inline Extensible Business Reporting Language) includes: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Equity, (iv) the Consolidated Statements of Cash Flows, and (v) the Notes to Consolidated Financial Statements.	X
104	The cover page from BP Midstream Partners LP's Annual Report on Form 10-K for the year ended December 31, 2020, formatted in iXBRL.	X

* Management Contract or Compensatory Plan

** Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this Annual Report on Form 10-K and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act, except to the extent that the registrant specifically incorporates it by reference.

Item 16. FORM 10-K SUMMARY

Not applicable.

SIGNATURES

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

Date: February 25, 2021

BP MIDSTREAM PARTNERS LP
By: BP MIDSTREAM PARTNERS GP LLC,
its general partner

By: /s/ Craig W. Coburn
Craig W. Coburn
Chief Financial Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 25, 2021, by the following persons on behalf of the registrant and in the capacities indicated.

Name	Title
/s/ Robert P. Zinsmeister Robert P. Zinsmeister	Chief Executive Officer and Director (Principal Executive Officer) BP Midstream Partners GP LLC
/s/ Craig W. Coburn Craig W. Coburn	Chief Financial Officer and Director (Principal Financial Officer and Principal Accounting Officer) BP Midstream Partners GP LLC
/s/ J. Douglas Sparkman J. Douglas Sparkman	Chairman of the Board of Directors BP Midstream Partners GP LLC
/s/ Jack T. Collins Jack T. Collins	Director BP Midstream Partners GP LLC
/s/ Clive Christison Clive Christison	Director BP Midstream Partners GP LLC
/s/ Walter Clements Walter Clements	Director BP Midstream Partners GP LLC
/s/ Robert Malone Robert Malone	Director BP Midstream Partners GP LLC
/s/ Michele F. Joy Michele F. Joy	Director BP Midstream Partners GP LLC

Exhibit 21

Subsidiaries of BP Midstream Partners LP
At December 31, 2020

Company Name	State of Organization
BP Two Pipeline Company LLC	Delaware
BP D-B Pipeline Company LLC	Delaware
BP River Rouge Pipeline Company LLC	Delaware

Joint Ventures	State of Organization
Mars Oil Pipeline Company LLC(1)	Delaware
Ursa Oil Pipeline Company LLC(2)	Delaware
KM Phoenix Holdings LLC(3)	Delaware
Mardi Gras Transportation System Company LLC(4)	Delaware
Caesar Oil Pipeline Company, LLC(4)	Delaware
Cleopatra Gas Gathering Company, LLC(4)	Delaware
Endymion Oil Pipeline Company, LLC(4)	Delaware
Proteus Oil Pipeline Company, LLC(4)	Delaware

(1) BP Midstream Partners LP owns a 28.5% interest in Mars Oil Pipeline Company LLC.
(2) BP Midstream Partners LP owns a 22.6916% interest in Ursa Oil Pipeline Company LLC.
(3) BP Midstream Partners LP owns a 25% interest in KM Phoenix Holdings LLC.
(4) BP Midstream Partners LP owns a 65% managing member interest in Mardi Gras Transportation System Company LLC. Mardi Gras Transportation System Company LLC owns a 56% interest in Caesar Oil Pipeline Company, LLC, a 53% interest in Cleopatra Gas Gathering Company, LLC, a 65% interest in Endymion Oil Pipeline Company, LLC and a 65% interest in Proteus Oil Pipeline Company, LLC.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-221213 on Form S-8 of our reports dated February 25, 2021, relating to the consolidated financial statements of BP Midstream Partners LP and subsidiaries and the effectiveness of BP Midstream Partners LP's internal control over financial reporting, appearing in this Annual Report on Form 10-K of BP Midstream Partners LP for the year ended December 31, 2020.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 25, 2021

Exhibit 23.2

Consent of Independent Auditors

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-221213) of BP Midstream Partners LP of our report dated February 18, 2021, with respect to the financial statements of Mars Oil Pipeline Company LLC, included in this Annual Report (Form 10-K) of BP Midstream Partners LP for the year ended December 31, 2020.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2021

Exhibit 31.1

**CERTIFICATION PURSUANT TO SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002**

I, Robert P. Zinsmeister, certify that:

1. I have reviewed this Annual Report on Form 10-K of BP Midstream Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    1. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    2. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    3. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    4. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    1. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    2. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2021

/s/ Robert P. Zinsmeister
Robert P. Zinsmeister
Chief Executive Officer and Director
BP Midstream Partners GP LLC
(the general partner of BP Midstream Partners LP)

Exhibit 31.2

**CERTIFICATION PURSUANT TO SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002**

I, Craig W. Coburn, certify that:

1. I have reviewed this Annual Report on Form 10-K of BP Midstream Partners LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    1. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    2. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    3. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    4. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    1. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    2. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 25, 2021

/s/ Craig W. Coburn
Craig W. Coburn
Chief Financial Officer and Director
BP Midstream Partners GP LLC
(the general partner of BP Midstream Partners LP)

Exhibit 32

**CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of BP Midstream Partners LP (the “Partnership”) on Form 10-K for the fiscal year ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 25, 2021

/s/ Robert P. Zinsmeister
Robert P. Zinsmeister
Chief Executive Officer and Director
BP Midstream Partners GP LLC
(the general partner of BP Midstream Partners LP)

/s/ Craig W. Coburn
Craig W. Coburn
Chief Financial Officer and Director
BP Midstream Partners GP LLC
(the general partner of BP Midstream Partners LP)

Exhibit 99.1

MARS OIL PIPELINE COMPANY LLC
Financial Statements
Years Ended December 31, 2020, 2019, and 2018

Exhibit 99.1

MARS OIL PIPELINE COMPANY LLC

Table of Contents

Report of Independent Auditors

To the Management Committee and Members
Mars Oil Pipeline Company LLC

We have audited the accompanying financial statements of Mars Oil Pipeline Company LLC, which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of income, members' capital and cash flows for each of the three years in the period ended December 31, 2020, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Mars Oil Pipeline Company LLC at December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

Adoption of ASU No. 2016-02

As discussed in Note 2 of the financial statements, Mars Oil Pipeline Company LLC changed its method of accounting for leases as a result of the amendments to the FASB Accounting Standards Codification resulting from Accounting Standards Update No. 2016-02, "Leases" (Topic 842), effective January 1, 2020. Our opinion is not modified with respect to this matter.

/s/ Ernst & Young LLP

Houston, Texas
February 18, 2021

MARS OIL PIPELINE COMPANY LLC
BALANCE SHEETS

	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 26,695,751	$ 29,348,638
Accounts receivable, net		
Related parties	12,577,725	18,585,209
Third parties	6,045,871	5,461,901
Materials and supplies inventory	110,979	110,979
Allowance oil, net	970,015	2,759,770
Other current assets	—	1,039,264
Total current assets	46,400,341	57,305,761
Property, plant and equipment	302,919,000	302,076,157
Accumulated depreciation	(147,287,210)	(137,985,182)
Property, plant and equipment, net	155,631,790	164,090,975
Operating lease right of use assets - related parties, net	102,009,445	—
Advance for operations due from related party	538,000	538,000
Other assets	11,026,243	8,334,109
Total assets	$ 315,605,819	$ 230,268,845
LIABILITIES and MEMBERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 754,138	$ 1,161,981
Payable to related parties	6,457,452	6,623,373
Current operating lease liabilities - related parties	15,442,076	—
Total current liabilities	22,653,666	7,785,354
Long-term liabilities and deferred revenue	17,617,181	22,890,167
Noncurrent operating lease liabilities - related parties	85,453,870	—
Commitments and contingencies (Note 9)		
Members' capital	189,881,102	199,593,324
Total liabilities and members' capital	$ 315,605,819	$ 230,268,845

The accompanying notes are an integral part of these financial statements.

MARS OIL PIPELINE COMPANY LLC
STATEMENTS OF INCOME

	2020	2019	2018
Revenue			
Operating revenue – related parties	$ 187,321,454	$ 197,531,039	$ 167,277,925
Operating revenue – third parties	64,899,257	65,326,677	62,225,748
Product revenue – related parties	6,522,070	18,867,918	11,801,170
Total revenue	258,742,781	281,725,634	241,304,843
Costs and expenses			
Operations and maintenance - related parties	70,643,947	69,312,076	62,367,290
Operations and maintenance - third parties	1,549,459	1,429,885	796,798
Cost of product sold	7,086,632	14,686,124	11,128,238
General and administrative - related parties	4,938,092	6,047,989	4,578,286
General and administrative - third parties	152,938	112,643	246,267
Depreciation and amortization	10,057,404	10,004,993	9,998,461
Property taxes	2,737,450	2,551,078	2,427,553
Net gain from pipeline operations	(854,450)	(596,967)	(4,142,396)
Total costs and expenses	96,311,472	103,547,821	87,400,497
Operating income	162,431,309	178,177,813	153,904,346
Interest income	156,469	1,304,218	14,686
Net Income	$ 162,587,778	$ 179,482,031	$ 153,919,032

The accompanying notes are an integral part of these financial statements.

MARS OIL PIPELINE COMPANY LLC
STATEMENTS OF MEMBERS' CAPITAL

	Shell Midstream Partners, L.P.	BP Midstream Partners, L.P.	Total
Members' capital at December 31, 2017	$ 164,475,812	$ 65,560,290	$ 230,036,102
Impact of change in accounting principle [1]	(6,888,196)	(2,745,645)	(9,633,841)
Net income	110,052,108	43,866,924	153,919,032
Cash distributions	(119,262,000)	(47,538,000)	(166,800,000)
Members' capital at December 31, 2018	$ 148,377,724	$ 59,143,569	$ 207,521,293
Net income	128,329,652	51,152,379	179,482,031
Cash distributions	(133,998,150)	(53,411,850)	(187,410,000)
Members' capital at December 31, 2019	$ 142,709,226	$ 56,884,098	$ 199,593,324
Net income	116,250,261	46,337,517	162,587,778
Cash distributions	(123,194,500)	(49,105,500)	(172,300,000)
Members' capital at December 31, 2020	$ 135,764,987	$ 54,116,115	$ 189,881,102

[1] Impact of adoption of Topic 606, Revenue from Contracts with Customers effective January 1, 2018.

The accompanying notes are an integral part of these financial statements.

MARS OIL PIPELINE COMPANY LLC
STATEMENTS OF CASH FLOWS

	2020	2019	2018
Cash flows from operating activities			
Net income	$ 162,587,778	$ 179,482,031	$ 153,919,032
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	10,057,404	10,004,993	9,998,461
Net gain on pipeline operations	(854,450)	(596,967)	(4,142,396)
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable - related parties	6,007,485	(2,137,737)	(721,103)
(Increase) decrease in accounts receivable - third parties	(583,970)	(552,649)	(1,563,301)
(Increase) decrease in materials and supplies inventory and allowance oil, net	2,644,205	6,228,033	(8,493)
(Increase) decrease in other assets	(3,521,746)	(1,756,378)	(2,221,159)
Increase (decrease) in deferred revenue	(5,272,986)	4,513,750	8,742,574
Increase (decrease) in accounts payable, accrued and other liabilities - related parties	(165,921)	1,601,450	457,713
Increase (decrease) in accounts payable, accrued and other liabilities - third parties	(1,046,642)	309,921	(182,547)
Net cash provided by operating activities	169,851,157	197,096,447	164,278,781
Cash flows from investing activities			
Capital expenditures	(204,044)	(541,035)	(570,711)
Net cash used in investing activities	(204,044)	(541,035)	(570,711)
Cash flows from financing activities			
Distributions to members	(172,300,000)	(187,410,000)	(166,800,000)
Net cash used in financing activities	(172,300,000)	(187,410,000)	(166,800,000)
(Decrease) increase in cash and cash equivalents	(2,652,887)	9,145,412	(3,091,930)
Cash and cash equivalents at the beginning of the period	29,348,638	20,203,226	23,295,156
Cash and cash equivalents at the end of the period	$ 26,695,751	$ 29,348,638	$ 20,203,226
Supplemental cash flow disclosures			
Change in accrued capital expenditures	$ 638,799	$ (440,708)	$ (36,739)

The accompanying notes are an integral part of these financial statements.

1. Organization and Business

Mars Oil Pipeline Company LLC ("Mars," "we," "us" or "our") owns a pipeline system for the transportation of crude oil from Mississippi Canyon Block 807 in the Gulf of Mexico, offshore Louisiana, to Clovelly, Louisiana. The Mars pipeline system is approximately 160 miles in length and has 16-, 18- and 24-inch diameter lines with mainline capacity of up to 600,000 barrels per day. The Mars pipeline system is regulated by the Federal Energy Regulatory Commission ("FERC"), where applicable, and tariff rates are calculated in accordance with guidelines established by the FERC.

Mars is 71.5% owned by Shell Midstream Partners, L.P. ("Shell Midstream") and 28.5% owned by BP Midstream Partners, L.P. ("BP Midstream") (collectively, the "Members"). In accordance with the LLC agreement, the historical relative sharing ratios between the Members for all revenues, costs and expenses is based on Member percentages. Mars is an LLC, and as such, no Member is liable for debts, obligations or liabilities, including under a judgment decree or order of a court; and we shall continue until such time as a certificate of cancellation is filed with the Secretary of the State of Delaware.

As per the Operating Agreement dated April 15, 1996 (the "Operating Agreement") between Mars and Shell Pipeline Company LP ("Shell Pipeline" or "Operator"), an indirect wholly-owned subsidiary of Shell Oil Company ("Shell Oil"), operates the Mars pipeline system and monitors the activity at the Clovelly Storage Terminal (the "Mars Cavern"), which consists of crude petroleum storage caverns and all ancillary components on behalf of the Members. The Mars Cavern itself is owned and operated by the Louisiana Offshore Oil Port LLC's ("LOOP").

2. Recent Accounting Pronouncements

Standards Adopted as of January 1, 2020

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-13 to Topic 326, Financial Instruments — Credit Losses: Measurement of Credit Losses on Financial Instruments, which replaces the current incurred loss impairment method with a method that reflects expected credit losses on financial instruments. The measurement of current expected credit losses under the new guidance is applicable to financial assets measured at amortized cost, including third-party trade receivables. We adopted the new standard effective January 1, 2020, using the modified retrospective method for all financial assets measured. No cumulative-effect adjustment to retained earnings was required upon adoption. The adoption of ASU 2016-13 did not have a material impact on our financial statements.

In February 2016, the FASB issued ASU 2016-02 to Topic 842, Leases. As permitted, we adopted the new lease standard (as defined in *Note 6 — Leases*) using the modified retrospective approach, effective January 1, 2020, which provides a method for recording existing leases at the beginning of the period of adoption. As such, results and balances prior to January 1, 2020 were not adjusted and continue to be reported in accordance with our historical accounting under previous generally accepted accounting principles in the United States ("GAAP"). See *Note 6 — Leases* for additional information and disclosures required by the new lease standard.

3. Summary of Significant Accounting Policies

We practice the following significant accounting policies, which are presented as an aid to understanding the financial statements.

Basis of Presentation
The accompanying financial statements have been prepared in accordance with GAAP. Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars.

Use of Estimates
The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. Management believes the estimates are reasonable.

Cash and Cash Equivalents
Cash and cash equivalents are comprised of cash on deposit at the bank.

Accounts Receivable
Our accounts receivable are primarily from purchasers and shippers of crude oil. These purchasers include, but are not limited to refiners, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our crude oil supply and logistics activities with our shippers.

We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. We establish provisions for losses on third-party accounts receivable due from shippers and operators based on current expected credit losses. As of December 31, 2020 and 2019, we had no allowance for doubtful accounts.

Inventories
Inventories of materials and supplies are carried at the lower of average cost or net realizable value.

Allowance Oil
A loss allowance factor of 0.1% to 0.015% per transported barrel is incorporated into applicable crude oil tariffs to offset evaporation and other losses in transit. Allowance oil represents the net difference between the tariff pipeline loss allowance (“PLA”) volumes and the actual volumetric losses. We take title to any excess loss allowance when product losses are within an allowed level and we convert that product to cash periodically at prevailing market prices. Crude oil is also stored within the Mars Cavern. Gains and losses related to the Mars Cavern, including a standard loss accrual of 0.05% of net crude oil receipts, also cause the allowance oil balance to increase or decrease, respectively.

Allowance oil is valued at cost using the average market price for the relevant type of crude oil during the month the product was transported. At the end of each reporting period, we assess the carrying value of our allowance oil and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. We record estimated losses expected to arise upon emptying the Mars Cavern, derived from historical net losses. As a result, Allowance oil, net as presented on the accompanying balance sheets includes net cavern loss accruals of $904,900 and $635,300 at December 31, 2020 and 2019, respectively.

Cost of product sold in 2020, 2019 and 2018 presented within the accompanying statements of income represent the cost of sales of allowance oil and any net realizable value adjustments recorded during the reporting period. See Revenue Recognition discussed below.

Other Current Assets
With the adoption of FASB ASU 2016-02 to Topic 842, Leases, effective January 1, 2020, prior balances were not adjusted and continue to be reported in accordance with our historical accounting under previous GAAP. Our right of use lease agreement with LOOP, an affiliate of Shell Pipeline, for the terminaling of crude oil in the Mars Cavern, which is renewed annually is now reflected as Operating lease right-of-use assets on the accompanying balance sheets. At December 31, 2019, the prepaid rent on the cavern lease of $1,039,264 was included in Other current assets within the accompanying balance sheets. Rental expense of $1,459,315 and $1,321,894 for the rental agreement is included in Operations and maintenance in the accompanying statements of income for 2019 and 2018, respectively. For further discussion of the lease arrangements, refer to *Note 6 - Leases*.

Property, Plant and Equipment, net
Property, plant and equipment, net is stated at its historical cost of construction, or upon acquisition, at either the fair value of the assets acquired or the historical carrying value to the entity that placed the asset in service. Expenditures for major renewals and betterments are capitalized while minor replacements, maintenance and repairs which do not improve or extend asset life are expensed when incurred. For constructed assets, all construction-related direct labor and material costs, as well as indirect construction costs are capitalized. Gains and losses on the disposition of assets are recognized on the accompanying balance sheets against the accumulated depreciation unless the retirement was an abnormal or extraordinary item.

We compute depreciation using the straight-line method based on estimated economic lives. We have historically computed depreciation using the straight-line method based on estimated economic lives prescribed by the FERC, which are 30 years for right of way, line pipe, line pipe fittings, pipeline construction, buildings, pumping equipment, other station equipment, oil tanks and delivery facilities; 20 years for office furniture and equipment; 15 years for communication systems and other work equipment; and 5 years for vehicles. We apply composite depreciation rates to functional groups of property having similar economic characteristics. These rates have historically ranged from 3.33% to 20%.

The following represent the remaining lives approved by FERC effective January 1, 2018: 18 to 23 years for right-of-way, line pipe, line pipe fittings, pipeline construction; 12 to 15 years for buildings, pumping equipment, other station equipment, office furniture and equipment; and 5 to 8 years for communication systems, vehicles and other work equipment (oil tanks and delivery facilities are no longer applicable to our assets). The composite depreciation rates effective January 1, 2018 range from 1.8% to 13.3%.

Other Assets

During 2015, we paid $7,553,757 to LOOP for replacing a Brine pipeline (also known as the "Brine String Project") owned by LOOP. We were contractually obligated to make capital improvements to the asset as part of the terms of an operating agreement with LOOP. The costs associated with the Brine String Project have been deferred and are being amortized over 10 years. Amortization expense of $755,376 was recorded for each of the years ended December 31, 2020, 2019 and 2018, and is included in Depreciation and amortization in the accompanying statements of income.

Asset Retirement Obligations

Asset retirement obligations ("AROs") represent contractual or regulatory obligations associated with the retirement of long-lived assets that result from acquisition, construction, development and/or normal use of the asset. We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses at fair value on a discounted basis when they are incurred and can be reasonably estimated. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when settled at the time the asset is taken out of service.

We continue to evaluate our AROs and future developments could impact the amounts we record. The demand for our pipelines depends on the ongoing demand to move crude oil through the system. Although individual assets will be replaced as needed, we expect our pipelines will continue to exist for an indeterminate economic life. As such, there is uncertainty around the timing of any asset retirement activities. As a result, we determined that there is not sufficient information to make a reasonable estimate of the AROs for our assets and we have not recognized any AROs for the year ended December 31, 2020 and 2019.

Impairments of Long-Lived Assets

Long lived assets of identifiable business activities are evaluated for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. These events include market declines that are believed to be other-than-temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment, such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying values based on the long-lived asset's ability to generate future cash flows on an undiscounted basis. When an indicator of impairment has occurred, we compare our management's estimate of forecasted undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether the assets are recoverable (i.e., the undiscounted future cash flows exceed the net carrying value of the assets). If the assets are not recoverable, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value. We determined that there were no asset impairments in the years ended December 31, 2020, 2019 and 2018.

Fair Value of Financial Instruments

Assets and liabilities requiring fair value presentation or disclosure are measured using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and are disclosed according to the quality of valuation inputs under the following hierarchy:

Level 1 - Quoted prices in an active market for identical assets or liabilities.
Level 2 - Inputs other than quoted prices that are directly or indirectly observable.
Level 3 - Unobservable inputs that are significant to the fair value of assets or liabilities.

The fair value of an asset or liability is classified based on the lowest level of input significant to its measurement. A fair value initially reported as Level 3 will be subsequently reported as Level 2 if the unobservable inputs become inconsequential to its measurement or corroborating market data becomes available. Asset and liability fair values initially reported as Level 2 will be subsequently reported as Level 3 if corroborating market data becomes unavailable.

The carrying amounts of our Accounts receivable, net, Other current assets, Accounts payable and accrued liabilities and Payables to related parties approximate their carrying values due to their short-term nature.

Concentration of Credit and Other Risks
A significant portion of our revenues and receivables are from related parties and other oil and gas companies. Although collection of these receivables could be influenced by economic factors affecting the oil and gas industry, management believes the risk of significant loss to be remote.

The following table shows revenues from third and related parties that accounted for 10% or more of Total revenue in the accompanying statements of income for the indicated periods:

	2020		2019		2018	
Shipper A (1)	$ 141,764,920	55.2 %	$ 160,177,153	56.8 %	$ 128,332,363	55.2 %
Shipper B (1)	47,490,479	18.5 %	56,566,806	20.0 %	51,013,830	21.9 %
Shipper C (2)	20,063,672	7.8 %	19,259,883	6.8 %	29,194,008	12.6 %

(1) Related party shipper
(2) Third-party shipper

There were no receivables from third parties that accounted for 10% or more of Accounts receivable, net in the accompanying balance sheets as of December 31, 2020 and 2019. The following table shows receivables from related parties that accounted for 10% or more of Accounts receivable, net in the accompanying balance sheets for the indicated dates:

	December 31,			
	2020		2019	
Shipper A	$ 9,265,464	50.0 %	$ 13,956,228	58.0 %
Shipper B	3,109,365	17.0 %	5,451,978	22.7 %

Development and production of crude oil in the service area of the pipeline are subject to, among other factors, prices of crude oil, as well as federal and state energy policy, which are not within our control.

We have concentrated credit risk for cash by maintaining deposits in a major bank, which may at times exceed amounts covered by insurance provided by the United States Federal Deposit Insurance Corporation (“FDIC”). We monitor the financial health of the bank and have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk. As of December 31, 2020 and 2019, we had $26,445,751 and $29,098,638, respectively, in cash and cash equivalents in excess of FDIC limits.

Net Gain on Pipeline Operations
We experience volumetric gains and losses from our pipeline operations that may arise from factors such as shrinkage or measurement inaccuracies within tolerable limits. Gains and losses from pipeline operations related to allowance oil are presented net in the accompanying statements of income as Net gain from pipeline operations. Prior to January 1, 2018, Net (gain) loss on pipeline operations that are related to allowance oil are presented net in the accompanying statements of income as net (gain) loss on pipeline operations. Beginning January 1, 2018, volumetric losses are recorded under Operating revenue in the accompanying statements of income.

Revenue Recognition
Our revenues are primarily generated from the transportation and storage of crude oil through our pipelines and storage caverns. We recognize revenue when we transfer promised goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. We recognize revenue through the application of a five step model, which includes: identification of the contract; identification of the performance obligations; determination of the transaction price; allocation of the transaction price to the performance obligations; and recognition of revenue as the entity satisfies the performance obligations.

See *Note 7 – Revenue Recognition* for information and disclosures related to revenue from contracts with customers.

Taxes
As an LLC, we have not historically incurred income tax expense in accordance with the provisions of the Internal Revenue Code, are not subject to U.S. federal income taxes. Rather, each Member includes its allocated share of our income or loss in its own federal and state income tax returns. We are responsible for various state property and ad valorem taxes, which are recorded in Property taxes in the accompanying statements of income.

4. Property, Plant and Equipment

Property, plant and equipment consisted of the following at December 31, 2019 and 2018:

	December 31,	
	2020	**2019**
Rights-of-way	$ 10,384,612	$ 10,384,612
Buildings	5,670,551	5,670,551
Line pipe, equipment and other pipeline assets	285,135,111	283,952,441
Office, communication and data handling equipment	1,086,810	1,086,810
Construction in progress	641,916	981,743
Total	302,919,000	302,076,157
Accumulated depreciation	(147,287,210)	(137,985,182)
Property, plant and equipment, net	**$ 155,631,790**	**$ 164,090,975**

Depreciation expense on property, plant and equipment is included in Depreciation and amortization in the accompanying statements of income for the years ended December 31, 2020, 2019 and 2018 in the amounts of $9,302,028, $9,249,618 and $9,243,085, respectively.

5. Related Party Transactions

We derive a significant portion of our operating and product revenues from related parties, which are based on published tariffs and contractual agreements, and amounted to $193,843,524, $216,398,957 and $179,079,095 for the years ended December 31, 2020, 2019 and 2018, respectively. All such transactions are within the ordinary course of business. At December 31, 2020 and 2019, we had affiliate receivables of $12,577,725 and $18,585,209, respectively.

We have no employees and rely on the Operator to provide personnel who perform daily operating and administrative duties on our behalf. In accordance with the terms of the Operating Agreement, we were charged aggregate expenses, which were incurred by the Operator on our behalf, of $13,461,165, $13,395,904 and $14,175,386 for the years ended December 31, 2020, 2019 and 2018, respectively. These expenses are individually included within Operations and maintenance, or General and administrative in the accompanying statements of income depending on the nature of the charge. Payments made by Shell Pipeline on our behalf for capital projects totaled $192,873, $185,781 and $128,730 for the years ended December 31, 2020, 2019 and 2018, respectively.

Substantially all expenses we incur are paid by Shell Pipeline on our behalf. At December 31, 2020 and 2019, we owed $804,122 and $607,914, respectively, to reimburse Shell Pipeline for these expenses. As of both December 31, 2020 and 2019, we had a receivable balance of $538,000 from Shell Pipeline, which is comprised of advance payments we made to Shell Pipeline to fund operating expenses. This balance is presented as Advance for operations due from related party on the accompanying balance sheets.

Employees who directly or indirectly support our operations participate in the pension, postretirement health and life insurance and defined contribution benefit plans sponsored by Shell Oil, which includes other Shell Oil subsidiaries. Our share of pension and postretirement health and life insurance costs for the years ended December 31, 2020, 2019 and 2018 were $592,173, $569,997 and $445,300, respectively. Our share of defined contribution benefit plan costs for the same periods were $222,105, $228,889 and $177,465, respectively. Pension and defined contribution benefit plan expenses are included in General and administrative in the accompanying statements of income.

We have several lease agreements with LOOP for cavern space. At December 31, 2020 and 2019, we owed $5,340,327 and $5,443,289, respectively, to LOOP for these expenses. During the years ended December 31, 2020, 2019 and 2018, payments made to LOOP for costs associated with cavern operations and usage were $62,327,012, $61,914,343 and $54,653,722, respectively, and are included primarily in Operations and maintenance within the accompanying statements of income.

We also have a lease agreement with a related party for usage of space located at the West Delta 143 "A", "B" and "C" offshore platform. At December 31, 2020 and 2019, we owed $313,003 and $556,120, respectively, for the related lease expenses. For the years ended December 31, 2020, 2019 and 2018, payments made to our related party for costs associated with the Lease of Platform Space ("LOPS") and Common Facility Fees ("CFF") at West Delta 143 "A", "B" and "C" were $7,255,161, $6,768,648 and $6,578,933, respectively.

For further discussion of the lease arrangements with our related parties, refer to *Note 6 - Leases*.

6. Leases

Adoption of ASC Topic 842 "Leases"

On January 1, 2020, we adopted ASC Topic 842 (the "new lease standard") by applying the modified retrospective approach to all leases on January 1, 2020. Under this guidance, lessees are required to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases. We elected the package of practical expedients upon transition that permits us to not reassess (1) whether any contracts entered into prior to adoption are or contain leases, (2) the lease classification of existing leases and (3) initial direct costs for any leases that existed prior to adoption.

Upon adoption on January 1, 2020, we recognized operating lease right-of-use ("ROU") assets and corresponding lease liabilities of $112,729,044. The accounting for finance leases (capital leases) was substantially unchanged.

Lessee accounting

We determine if an arrangement is or contains a lease at inception. Our assessment is based on (1) whether the contract involves the use of a distinct identified asset, (2) whether we obtain the right to substantially all the economic benefit from the use of the asset throughout the period and (3) whether we have the right to direct the use of the asset. Leases are classified as either finance leases or operating leases. A lease is classified as a finance lease if any one of the following criteria are met: the lease transfers ownership of the asset by the end of the lease term, the lease contains an option to purchase the asset that is reasonably certain to be exercised, the lease term is for a major part of the remaining useful life of the asset or the present value of the lease payments equals or exceeds substantially all of the fair value of the asset. A lease is classified as an operating lease if it does not meet any one of these criteria. The lease classification affects the expense recognition in the statement of income. Operating lease costs are recorded entirely in operating expenses. Finance lease costs are split, where amortization of the ROU asset is recorded in operating expenses and an implied interest component is recorded in interest expense.

Under the new lease standard, operating leases (as lessee) are included in Operating lease right-of-use assets- related party. Operating lease amortization of right of use assets- related party, Operating lease right of use assets- related party, net, Current operating lease liabilities- related party and Noncurrent operating lease liabilities- related party in our accompanying balance sheets. ROU assets and lease liabilities are recognized at commencement date based on the present value of the future minimum lease payments over the lease term. The ROU asset includes any lease payments made but excludes lease incentives and initial direct costs incurred, if any. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term.

Lease extensions

Many of our leases have options to either extend or terminate the lease. In determining the lease term, we considered all available contract extensions that are reasonably certain of occurring.

Significant assumptions and judgments

Incremental borrowing rate. As most of our leases do not provide an implicit interest rate, we use our incremental borrowing rate ("IBR") at the commencement of the lease and estimate the IBR for each lease agreement taking into consideration lease contract term, collateral and entity credit ratings, and use sensitivity analyses to evaluate the reasonableness of the rates determined.

Lease balances and costs

All of the lease agreements that we have entered into are classified as operating leases.

Effective April 1, 1996, we entered into an agreement to lease usage of offshore platform space located at West Delta 143 (“WD 143”) from affiliates of Shell Oil and BP. The agreement, as amended on December 1, 2015, requires annual minimum lease payments of $1,809,370 for LOPS at WD143 “B” related to the pump station and $32,800 for LOPS related to platform space at WD 143 “A”, adjusted annually based on the Wage Index Adjustment, as published by the Council of Petroleum Accountants Society (“COPAS”). In addition, the amendment requires an added minimum lease payment of $1,159,950 per year adjusted annually based on the Wage Index Adjustment for LOPS at WD 143 “C” related to the Olympus pipeline. The agreements for WD 143 “A”, “B” and “C” shall terminate upon removal of the operating equipment located on each of the platforms as specified in the terms of the agreement. Total expenses incurred under the agreement for LOPS at WD 143, inclusive of rentals and CFF, for the years ended December 31, 2020, 2019 and 2018 were $7,255,161, $6,768,648 and $6,578,933, respectively. Total amounts owed to related parties relating to the agreement, inclusive of rentals and CFF, were $313,003 and $556,120 as of December 31, 2020 and 2019, respectively.

Effective June 10, 1994, we entered into a lease agreement to use a cavern owned by LOOP as a crude oil storage facility where LOOP shall receive and store Mars crude petroleum on a continuous basis. The initial lease term of the agreement ended December 31, 2011 and the extended terms will automatically renew for four separate five-year terms through 2031. The agreement is cancellable at our discretion by giving notice of termination not less than one year prior to the end of each five year extension. The terms of the agreement require an annual prepayment of the lease amount; and these payments were $1,656,958, $1,556,982 and $1,410,482 for the years ended December 31, 2020, 2019 and 2018, respectively. The annual rental expense for the years ended December 31, 2020, 2019 and 2018 were $1,663,982, $1,459,315 and $1,321,894, respectively. The agreement also requires an annual fixed base service fee in addition to variable charges based on throughput. The agreement requires a minimum base service fee of $400,000 per year adjusted by the change in the Gross Domestic Project-Implicit Price Deflator as published by the U.S. government. The 2020 adjusted minimum base service fee payment under the agreement was $614,104.

Effective May 1, 2019, Mars entered into the Ancillary Cavern Services Agreement with LOOP to lease additional cavern space for crude oil storage. The primary term of this agreement was a one-year commitment to lease the cavern space from May 1, 2019 through April 30, 2020 at a cost of $1,100,000 per month. There are four one-year extension terms as part of this agreement, and on April 10th, 2020 Mars elected to exercise the first one-year extension at a cost of $1,200,000 per month. Total rental expense for years ended December 31, 2020, and 2019, were $14,000,000 and $8,800,000, respectively.

Apart from the lease agreements listed above, Mars has two surface leases with third parties totaling $14,181, 13,329, and 13,275 in rental expense for the years ended December 31, 2020, 2019, and 2018, respectively.

The following tables summarize balance sheet data related to leases at December 31, 2020 and our lease costs as of and for the year ended December 31, 2020.

Leases	**Classification**	**December 31, 2020**
Assets		
Operating lease assets	Operating lease right-of-use assets - related parties, net	$ 102,009,445
Liabilities		
Current		
Operating	Current operating lease liabilities - related parties	$ 15,442,076
Noncurrent		
Operating	Noncurrent operating lease liabilities - related parties	85,453,870
Total lease liabilities		$ 100,895,946

Lease cost	Classification		December 31, 2020 [1]
Operating lease cost	Operations and maintenance - related parties	$	19,177,248

[1] Includes short-term lease costs of $4.4 million for the year ended December 31, 2020.

Other information

		December 31, 2020 [1]
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	(17,973,906)

[1] Includes short-term lease costs of $4.4 million for the year ended December 31, 2020.

	December 31, 2020
Weighted-average remaining lease term (years):	
Operating leases	11.4
Weighted-average discount rate:	
Operating leases	4.3 %

Annual maturity analysis

The future annual maturity of lease payments as of December 31, 2020 for the above lease obligations was:

Maturity of lease liabilities		Operating Leases [1]
2021	$	19,338,518
2022		19,338,695
2023		19,338,695
2024		9,738,695
2025		4,938,695
Remainder		59,596,855
Total lease payments	$	132,290,153
Less: Interest [2]		(31,394,207)
Present value of lease liabilities	$	100,895,946

[1] Lease payments adjust annually based on the Wage Index Adjustment, as published by COPAS.
[2] Calculated using the interest rate for each lease.

7. Revenue Recognition

The core principle of Topic 606, Revenue from Contracts with Customers and all related ASUs to this Topic (collectively, the "revenue standard") is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The revenue standard requires entities to recognize revenue through the application of a five-step model, which includes: identification of the contract; identification of the performance obligations; determination of the transaction price; allocation of the transaction price to the performance obligations; and recognition of revenue as the entity satisfies the performance obligations.

Our revenues are primarily generated from the transportation and storage of crude oil through our pipelines and storage facilities. To identify the performance obligations, we considered all the products or services promised in the contracts with customers, whether explicitly stated or implied based on customary business practices. Revenue is recognized when each performance obligation is satisfied under the terms of the contract. Each barrel of product transported or day of services provided is considered a distinct service that represents a performance obligation that would be satisfied over time if it were accounted for separately. The services provided over the contract period are a series of distinct services that are substantially the same, have the same pattern of transfer to the customer, and therefore, qualify as a single performance obligation. Since the customer simultaneously receives and consumes the benefits of services, we recognize revenue over time based on a measure of progress of volumes transported for transportation services contracts, number of days elapsed for stand ready-transportation service contracts or number of days elapsed for storage services contracts.

Product revenue related to allowance oil sales is recognized at the point in time when the control of the oil transfers to the customer.

For all performance obligations, payment is typically due in full within 30 days of the invoice date.

Disaggregation of Revenue – The following table provides information about disaggregated revenue by service type and customer type:

($ in millions)	2020	2019	2018
Transportation services revenue – third parties	$ 61.8	$ 63.8	$ 59.9
Transportation services revenue – related parties	180.5	196.1	164.3
Total transportation services revenue	242.3	259.9	224.2
Storage services revenue – third parties	3.1	1.5	2.3
Storage services revenue – related parties	6.8	1.4	3.0
Total storage services revenue	9.9	2.9	5.3
Product revenue – related parties	6.5	18.9	11.8
Total product revenue (1)	6.5	18.9	11.8
Total revenue	$ 258.7	$ 281.7	$ 241.3

(1) Product revenue is comprised of allowance oil sales.

Transportation services revenue – We have both long-term transportation contracts and month-to-month contracts for spot shippers that make nominations on our pipelines. Some of the long-term contracts entitle the customer to a specified amount of guaranteed capacity on the pipeline. Transportation services are charged at a per barrel rate or number of days elapsed. We apply the allocation exception guidance for variable consideration related to market indexing for long-term transportation contracts because (a) the variable payment relates specifically to our efforts to transfer the distinct service and (b) we allocate the variable amount of consideration entirely to the distinct service which is consistent with the allocation objective. Transportation services are billed monthly as services are rendered.

Our contracts and tariffs contain terms for the customer to reimburse us for losses from evaporation or other loss in transit in the form of allowance oil. Allowance oil represents the net difference between the tariff PLA volumes and the actual volumetric losses. We obtain control of the excess oil not lost during transportation, if any. Under the revenue standard, we include the excess oil retained during the period, if any, as non-cash consideration and include this amount in the transaction price for transportation services on a net basis. Our allowance oil is valued using the average market price of the relevant type of crude oil during the month product was transported. Gains from pipeline operations that relate to allowance oil are recorded in Net gain on pipeline operations in the accompanying statements of income.

As a result of FERC regulations, revenues we collect may be subject to refund. We establish reserves for these potential refunds based on actual expected refund amounts on the specific facts and circumstances. We had no reserves for potential refunds as of December 31, 2020 and 2019.

Deferred revenue – Under certain contracts with tiered pricing arrangements, we are entitled to receive payments in advance of satisfying our performance obligations under the contracts. We recognize a liability for these payments in excess of revenue recognized and present it as deferred revenue on our balance sheets.

Storage services revenue – Storage services are provided under a monthly spot-rate for uncommitted storage. Since the customer simultaneously receives and consumes the benefits of services, we recognize revenue over time based on the number of days elapsed. Storage services are billed monthly as services are rendered.

Product revenue – We generate revenue by selling accumulated allowance oil inventory to customers. Sale of allowance oil is recorded as product revenue, with specific cost based on a weighted average price per barrel recorded as cost of product sold.

Contract Balances – We perform our obligations under a contract with a customer by providing services in exchange for consideration from the customer. The timing of our performance may differ from the timing of the customer's payment, which results in the recognition of a contract asset or a contract liability. Although we did not have any contract assets as of December 31, 2020 and 2019, we recognize a contract asset when we transfer goods or services to a customer and contractually bill an amount which is less than the revenue allocated to the related performance obligation. We recognize deferred revenue (contract liability) when the customer's payment of consideration precedes our performance.

The following table provides information about receivables and contract liabilities from contracts with customers:

($ in millions)	January 1, 2020	December 31, 2020
Receivables from contracts with customers – third parties	$ 5.5	$ 6.0
Receivables from contracts with customers – related parties	18.4	12.6
Deferred revenue – related party	22.8	17.6

($ in millions)	January 1, 2019	December 31, 2019
Receivables from contracts with customers – third parties	$ 4.9	$ 5.5
Receivables from contracts with customers – related parties	15.2	18.4
Deferred revenue – related party	18.3	22.8

Significant changes in the deferred revenue balances with customers during the periods are as follows:

($ in millions)	December 31, 2018	2019 Additions [1]	December 31, 2019	2020 Reductions[2]	December 31, 2020
Deferred revenue – related party	$ 18.3	$ 4.5	$ 22.8	$ (5.2)	$ 17.6

[1] Deferred revenue additions resulted from collection of cash for unsatisfied performance obligations.
[2] Deferred revenue reductions resulted from lower volumes.

We currently have no assets recognized from the costs to obtain or fulfill a contract as of December 31, 2020 and 2019.

Remaining Performance Obligations - As of December 31, 2020, contracts with remaining performance obligations primarily include long-term dedication and transportation agreements.

The following table includes revenue expected to be recognized in the future related to performance obligations exceeding one year of their initial terms that are unsatisfied or partially unsatisfied as of December 31, 2020:

($ in millions)	Total	2021	2022	2023	2024	2025 and beyond
Revenue expected to be recognized on long-term dedication and transportation agreements	$ 317.6	$ 39.7	$ 39.7	$ 39.7	$ 39.7	$ 158.8

As an exemption, we do not disclose the amount of remaining performance obligations for contracts with an original expected duration of one year or less or for variable consideration that is allocated entirely to a wholly unsatisfied promise to transfer a distinct service that forms part of a single performance obligation.

8. Environmental Matters

We are subject to federal, state and local environmental laws and regulations. We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our net income in the period in which they are probable and reasonably estimable. For both December 31, 2020 and 2019, these costs and any related liabilities are not material.

9. Commitments and Contingencies

In the ordinary course of business, we are subject to various laws and regulations, including regulations of the FERC. In the opinion of management, we are in compliance with existing laws and regulations and are not aware of any violations that could materially affect our financial position, results of operations or cash flows. We are subject to several lease agreements, which are accounted for as operating leases and the minimum lease payments over the next five years are disclosed in *Note 6 - Leases*.

10. Subsequent Events

In preparing the accompanying financial statements, we have reviewed events that have occurred subsequent to December 31, 2020 through February 18, 2021, which is the date of the issuance of these financial statements. Any material subsequent event that occurred during this time has been properly disclosed in the financial statements.