American Midstream Partners, LP
Form 10-K
April 01, 2019

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

FORM 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
Or
o 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: 001-35257

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

Delaware	27-0855785
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2103 CityWest Boulevard Building #4, Suite 800 Houston, Texas	77042
(Address of principal executive offices)	(Zip code)

(346) 241-3400
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partnership Interests	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x
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 o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No o

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

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	o	Accelerated filer	x
Non-accelerated filer	o	Smaller reporting company	o
		Emerging growth company	o

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: o

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2018, was $387,019,464. The aggregate market value was computed by reference to the closing price of the registrant's common units on the New York Stock Exchange on June 29, 2018.

There were 54,212,212 common units, 11,342,197 Series A preferred units and 9,514,330 Series C preferred units of American Midstream Partners, LP outstanding as of March 18, 2019. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

Documents Incorporated by Reference: None.

TABLE OF CONTENTS

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "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 (the "Exchange Act"). You can typically identify forward-looking statements by the use of words, such as "may," "could," "intend," "will," "would," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in Item 1A. Risk Factors of this Annual Report on Form 10-K for the year ended December 31, 2018 (the "2018 Form 10-K") as well as the following risks and uncertainties:

- our ability to complete the Pending Merger (as defined herein) in a timely manner, or at all;
- greater than expected operating costs, customer loss, business disruption and employee attrition as a result of the Pending Merger;
- diversion of management time on the Pending Merger;
- our ability to refinance our credit facility before its scheduled maturity in September 2019 on terms acceptable to us, or at all, and the associated costs;
- our ability to maintain compliance with covenants and ratios in our Credit Agreement (as defined herein) and other debt instruments or obtain necessary waivers or amendments from lenders;
- the impact of our suspension of distributions and contractual restrictions on our ability to declare and make cash distributions on our common units, including under our Partnership Agreement (as defined herein) and Credit Agreement;
- our ability to execute on our capital allocation strategy, including sales of non-core assets, receipt of expected proceeds and reduction in leverage;
- our ability to timely and successfully identify, consummate and integrate acquisitions and organic growth projects, including the realization of all anticipated benefits of any such transactions;
- any adverse impact of our doubt as to our ability to continue as a going concern;
- our ability to generate sufficient cash from operations to pay distributions to unitholders and the board of directors of our General Partner (the "Board") discretionary determination as to the level of cash distributions to unitholders;
- the demand for natural gas, refined products, condensate or crude oil and NGL products by the petrochemical, refining or other industries;
- the performance of certain of our current and future projects and unconsolidated affiliates that we do not control and disruptions to cash flows from our joint ventures due to contractual, operational or other issues;
- severe weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- security threats such as terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;

- general economic, market and business conditions, including industry changes and the impact of consolidations and changes in competition;
- the level of creditworthiness of counterparties to transactions;
- the amount of collateral required to be posted from time to time in our transactions;
- the level and success of natural gas and crude oil drilling around our assets and our success in connecting natural gas and crude oil supplies to our gathering and processing systems;
- the timing and extent of changes in natural gas, crude oil, NGLs and other commodity prices, interest rates and demand for our services;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity, interest rate and weather risks;
- our dependence on a relatively small number of customers for a significant portion of our gross margin;
- our ability to renew our gathering, processing, transportation and terminal contracts;
- our ability to successfully balance our purchases and sales of natural gas;

- our ability to grow through contributions from affiliates, acquisitions and internal growth projects;
- the impact or outcome of any legal proceedings, including any related to the Pending Merger;
- adverse actions by third parties beyond our control, including ArcLight and joint venture partners;
- costs associated with compliance with environmental, health and safety, and pipeline regulations; and
- the cost and effectiveness of our remediation efforts with respect to the material weaknesses discussed in Part II. Item 9A. Controls and Procedures of this 2018 Form 10-K.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this 2018 Form 10-K will prove to be accurate. Some of these, and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements, are more fully described herein in Item 1A. Risk Factors. Statements in this 2018 Form 10-K speak as of the date of this report. Except as may be required by applicable securities laws, we undertake no obligation to publicly update or advise investors of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

As generally used in the energy industry and in this 2018 Form 10-K, the identified terms have the following meanings:

Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
Bbl/d	Barrels per day.
Bcf	Billion cubic feet.
Btu	British thermal unit; a measurement of energy.
Condensate	Liquid hydrocarbons present in casing head gas that condense within the gathering system and are removed prior to delivery to the natural gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
/d	Per day.
FERC	Federal Energy Regulatory Commission.
Fractionation	Process by which natural gas liquids are separated into individual components.
GAAP	Accounting principles generally accepted in the United States of America.
Gal	Gallons.
Mgal	Thousand gallons.
MBbl	Thousand barrels.
Mboe	Thousand barrels of oil equivalents.
MMgal	Million gallons.

MMBbl	Million barrels.
MMBtu	Million British thermal units.
Mcf	Thousand cubic feet.
MMcf	Million cubic feet.
NGL or NGLs	Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Throughput	The volume transported or passing through a pipeline, plant, terminal or other facility during a particular period.

As used in this 2018 Form 10-K, unless the context otherwise requires, "we," "us," "our," the "Partnership" and similar terms refer to American Midstream Partners, LP, together with its consolidated subsidiaries. References in this 2018 Form 10-K to our "General Partner" refer to American Midstream GP, LLC.

PART I

Item 1. Business

Overview

American Midstream Partners, LP is a Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We provide critical midstream infrastructure that links producers of natural gas, crude oil, NGLs and condensate to numerous intermediate and end-use markets. We engage in the business of gathering, treating, processing and transporting natural gas; gathering, transporting, treating and fractionating NGLs; and gathering, storing and transporting crude oil and condensates.

Our primary assets are strategically located in some of the most prolific onshore and offshore producing regions and key demand markets in the United States. Our liquids and natural gas gathering and natural gas processing assets are primarily located in the Permian Basin of West Texas, the Cotton Valley/Haynesville Shale of East Texas, the Eagle Ford Shale of South Texas, the Bakken Shale of North Dakota and offshore in the Gulf of Mexico. Our liquid pipelines and natural gas transportation assets are located in Alabama, Arkansas, Louisiana, Mississippi, North Dakota, Texas and Tennessee and offshore in the Gulf of Mexico. Additionally, we operate a fleet of NGL gathering and transportation trucks in the Eagle Ford Shale and the Permian Basin.

A significant portion of our cash flow is derived from our investments in unconsolidated affiliates, which includes:

- a 66.7% operated interest in Destin Pipeline Company, L.L.C. ("Destin"), a natural gas pipeline;
- a 66.7% operated interest in Okeanos Gas Gathering Company, LLC ("Okeanos"), a natural gas gathering system;
- a 50.0% non-operated interest in Cayenne Pipeline, LLC ("Cayenne"), a NGL pipeline;
- a 35.7% non-operated interest in the Class A units of Delta House Floating Production Systems LLC ("FPS") and of Delta House Oil and Gas Lateral LLC ("OGL") (collectively referred to herein as "Delta House"), which is a floating production system platform and related pipeline infrastructure;
- a 25.3% non-operated interest in Wilprise Pipeline Company, L.L.C. ("Wilprise"), a NGL pipeline; and
- a 16.7% non-operated interest in Tri-States NGL Pipeline, L.L.C. ("Tri-States"), a NGL pipeline.

During 2018, we operated our business through the following five reportable segments. For further information regarding the assets included in each segment, please see Our Segments.

Gas Gathering and Processing Services. Our Gas Gathering and Processing Services segment provides “wellhead-to-market” services to producers of natural gas and NGLs, which include transporting raw natural gas from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs and selling or delivering pipeline quality natural gas and NGLs to various markets and pipeline systems.

Liquid Pipelines and Services. Our Liquid Pipelines and Services segment purchases and sells crude oil and provides crude oil gathering and transportation services from various receipt points including those with lease automatic custody transfer (“LACT”) facilities to delivery points in various markets.

Natural Gas Transportation Services. Our Natural Gas Transportation Services segment transports and delivers natural gas from producing wells, pipeline interconnects, and other receipt points for shippers and other customers, which include local distribution companies ("LDCs"), utilities, industrial, commercial and power generation customers.

Offshore Pipelines and Services. Our Offshore Pipelines and Services segment gathers and transports natural gas and crude oil from various receipt points to other pipeline interconnects, onshore facilities and other delivery points.
Terminalling Services. Our Terminalling Services segment provided above-ground leasable storage services at our marine terminals that supported various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including petroleum products, distillates, chemicals and agricultural products.

During 2018, in order to improve operational alignment, we reorganized our reporting structure such that the operations of the following assets have been transferred between segments as follows:

- our Cushing, Oklahoma assets have been moved from our Terminalling Services segment to our Liquid Pipelines and Services segment as a result of the dispositions of our refined products terminals (“Refined Products”) and our marine liquids terminals (“Marine Products”);
- our AMID NGL Trucking asset (formerly part of Crude Oil Supply and Logistics ("COSL")) has been moved from our Liquid Pipelines and Services segment to our Gas Gathering and Processing Services segment;
- our Cayenne asset has been moved from our Offshore Pipelines and Services segment to our Liquid Pipelines and Services segment; and
- our Chalmette System assets have been moved from our Natural Gas Transportation Services segment to our Offshore Pipelines and Services segment.

These reporting changes do not impact our previously reported consolidated financial results, but our prior period segment results have been recast to reflect the changes.

During 2018, we entered into, and completed, the following definitive agreements for the sale of certain of our assets:

- On June 18, 2018, we entered into a definitive agreement for the sale of Marine Products to institutional investors for approximately $210 million in cash, subject to working capital adjustments. On July 31, 2018, we completed the sale of Marine Products. Net proceeds from this disposition were $208.6 million, exclusive of $5.7 million in advisory fees and other costs, and were used to repay borrowings outstanding under our Credit Agreement.
- On November 15, 2018, we entered into a definitive agreement for the sale of Refined Products to Sunoco LLC for approximately $125 million in cash, subject to working capital adjustments. On December 20, 2018, we completed the sale of Refined Products. Net proceeds from this disposition were $125 million, exclusive of $3.7 million in advisory fees and other costs, and were used to repay borrowings outstanding under our Credit Agreement.

Subsequent to the dispositions of Refined Products and Marine Products, we eliminated the Terminalling Services segment and we currently operate our business through the remaining four reportable segments. Additionally, as a result of the disposition of the Propane Marketing Services business ("Propane Business") in 2017, we eliminated the Propane Marketing Services segment, which is included in Discontinued Operations. For more information on our dispositions, see Part II. Item 8. Note 5. Dispositions of this 2018 Form 10-K.

Pending Merger

On September 27, 2018, the Board received an unsolicited non-binding proposal from Magnolia Infrastructure Holdings, LLC (“Magnolia”), an affiliate of ArcLight Capital Partners, LLC (“ArcLight”), pursuant to which Magnolia or one of its affiliates would acquire all common units of the Partnership that Magnolia and its affiliates do not already own in exchange for $6.10 per common unit. The Board delegated authority to review and approve the proposal to the independent Conflicts Committee of the Board.

On January 2, 2019, the Board received a revised unsolicited non-binding proposal from Magnolia, pursuant to which Magnolia, or one of its affiliates, would acquire all common units of the Partnership that Magnolia and its affiliates do not already own in exchange for $4.50 per common unit. The other proposed terms of the potential transaction remained as set forth in the original non-binding proposal received on September 27, 2018. Consistent with its prior delegation of authority, the Board referred the revised offer to the Conflicts Committee of the Board.

On March 17, 2019, as recommended by the Conflicts Committee of the Board and after receiving the opinion of the financial advisor of the Conflicts Committee, Evercore, the Partnership and our General Partner entered into an

Agreement and Plan of Merger (the "Merger Agreement") with Anchor Midstream Acquisition, LLC, a Delaware limited liability company ("Proposed Parent"), Anchor Midstream Merger Sub, LLC, a Delaware limited liability company ("Proposed Merger Sub"), and High Point Infrastructure Partners, LLC, a Delaware limited liability company ("HPIP"), pursuant to which Proposed Merger Sub will merge with and into the Partnership, with the Partnership surviving as a direct wholly owned subsidiary of our General Partner and Proposed Parent (the "Pending Merger").

If the Pending Merger is completed, at the effective time of the Merger, each issued and outstanding common unit of the Partnership, other than those held by Proposed Parent and its affiliates, will be converted into the right to receive $5.25 per common unit in cash without any interest thereon (the "Merger Consideration"). The Incentive Distribution Rights (as defined in the Fifth Amended and Restated Agreement of Limited Partnership (as amended, the "Partnership Agreement")) in the Partnership issued and outstanding immediately prior to the effective time of the Pending Merger shall, as a result of the merger, automatically be canceled and cease to exist, with no consideration delivered in respect thereof. The common units held by Proposed Parent and its affiliates and the General Partner Interest (as defined in our Partnership Agreement) issued and outstanding immediately prior to the effective time of the Pending Merger shall be unaffected by the Pending Merger and shall remain outstanding.

The Pending Merger is expected to close in the second quarter of 2019, pending the satisfaction of certain customary conditions. Upon completion of the transactions contemplated by the Merger Agreement, we will no longer have publicly listed or registered common units, although we may still be required to file reports with the SEC pursuant to the indenture governing our outstanding senior notes.

If the Pending Merger is consummated, it will be a taxable event to our unaffiliated unitholders with recognition of gain or loss in the same manner as if they had sold their units in us for the amount specified in the Merger Agreement.

Under the Partnership Agreement, the Pending Merger is required to be approved by a majority of the outstanding common units and preferred units, voting as a class, and each class of preferred units. Affiliates of ArcLight own approximately 51% of such voting power and prior to the execution of the Merger Agreement, affiliates of ArcLight delivered to the Partnership a written consent approving the Pending Merger. As such, the Pending Merger has been approved by the limited partners of the Partnership, and the Partnership will not hold a meeting of its unitholders to approve the merger. Accordingly, as permitted by the Delaware Revised Uniform Partnership Act and our Partnership Agreement, by resolutions adopted by written consent dated March 17, 2019, affiliates of ArcLight holding a majority of the outstanding units on such date approved the Pending Merger pursuant to the terms of the Merger Agreement.

The closing of the Pending Merger is subject to conditions described more completely in the Merger Agreement, including (i) certain regulatory approvals, (ii) effecting modifications to our Credit Agreement, including entrance into the Waiver (as defined below), and (iii) other customary closing conditions. The Merger Agreement includes customary representations and warranties. It also includes customary covenants and agreements, including interim operating covenants and non-solicitation provisions and includes customary termination provisions, including if the Pending Merger has not been completed by July 31, 2019.

Our Segments

During 2018, we operated our business through five reportable segments as follows:

Gas Gathering and Processing Services Segment

In our Gas Gathering and Processing Services segment, we have the following assets:

Lavaca System

The Lavaca System consists of 226 miles of high and low-pressure pipelines ranging from two to 12 inches in diameter with 24,000 horsepower of leased compression,14,000 horsepower of owned compression and associated facilities located in the Eagle Ford Shale in Gonzales and Lavaca Counties, Texas. The Lavaca System currently has a design capacity of approximately 195 MMcf/d. Natural gas production gathered by the system is compressed and delivered to a third-party for processing or redelivered to producers for gas lift.

Longview System

The Longview gathering and processing system consists of approximately 620 miles of high and low pressure gathering lines with diameters ranging from two to twenty inches with a combined compression capacity of 19,980 horsepower. Our Longview System also contains two cryogenic processing plants with a design capacity of approximately 50 MMcf/d, one fractionation unit with 8,500 Bbl/d of capacity, product storage tanks, and truck racks to receive off-spec NGLs and condensate. The Longview System is located near Longview in Gregg County, Texas. Located adjacent to the Longview System is a rail facility designed to receive and deliver NGLs and condensate which commenced operations in the first quarter of 2016.

Chapel Hill System

The Chapel Hill gathering and processing system consists of approximately 90 miles of gathering lines with a combined compression capacity of 2,540 horsepower. Our Chapel Hill System also contains a cryogenic processing plant with a design capacity of approximately 20 MMcf/d, one fractionation unit with 1,250 Bbl/d of capacity, product storage tanks, and truck racks to deliver propane, butane, and natural gasoline. The Chapel Hill System is located near Tyler in Smith County, Texas.

Yellow Rose System

The Yellow Rose gathering and processing system consists of approximately 90 miles of high and low-pressure pipelines, a rich-gas gathering system and a 40 MMcf/d cryogenic processing plant, with pipeline takeaway for residue gas and liquids. The Yellow Rose System is located in the Permian Basin in Martin, Andrews and Dawson counties, Texas.

Chatom System

The Chatom System consists of a 20 MMcf/d refrigeration processing plant, a 1,600 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit and a 24-mile gas gathering system and compression capacity of 7,496 horsepower. The system is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi. The Chatom System gathers natural gas from onshore crude oil and natural gas wells in the Norphlet and Smackover formations in Alabama and Mississippi. Chatom also has a truck rack and the capability to receive and fractionate NGLs.

Bazor Ridge System

The Bazor Ridge gathering and processing system consists of approximately 169 miles of pipeline, with diameters ranging from three to eight inches, and three compressor stations with a combined compression capacity of 4,040 horsepower. Our Bazor Ridge System is located in Jasper, Clarke, Wayne and Greene counties of Mississippi. The Bazor Ridge System also contains an idled sour natural gas treating and cryogenic processing plant located in Wayne County, Mississippi, with four inlets and one discharge compressor with approximately 22.5MMcf/d of design capacity. The natural gas supply for our Bazor Ridge System is derived primarily from rich natural gas produced from crude oil wells targeting the mature Upper Smackover formation. Since 2016, the Bazor Ridge facility has been exclusively used as a central gathering and compression facility and processing has been re-routed to the Chatom System.

Glade Crossing

The Glade Crossing processing facility consists of a refrigeration unit, amine plant and dehydration equipment with a design capacity of 10 MMcf/d. The facility is located near Laurel in Jones County, Mississippi.

Mesquite

We own 94.8% of American Midstream EnerTrade, LLC which owns an approximate 50% interest in the assets at the Mesquite NGL processing facility located near Midland, Texas. American Midstream EnerTrade’s assets include a 5,000 Bbl/d fractionation unit with truck and rail capabilities that facilitate the receipt and treatment of off-spec NGLs and condensate. The resulting products are sold via pipeline, truck, and rail.

AMID NGL Trucking (Formerly part of COSL)

We operate a fleet of 23 trucks in East Texas that assist in our NGL gathering and product delivery efforts.

Burns Point

Burns Point Plant is a cryogenic processing plant that is jointly owned by us and the plant operator, Enterprise Gas Processing, LLC ("Enterprise"). We hold a 50% undivided, non-operated interest in the Burns Point Plant. We acquired an interest in the asset group and not in a legal entity. We and Enterprise are proportionately liable for the liabilities. Outside of the rights and responsibilities of the operator, we and Enterprise have equal rights and obligations to the assets. Significant non-capital and maintenance capital expenditures, plant expansions and significant plant dispositions require the approval of both owners. The plant has been shut down since December 2017 due to maintenance issues and is expected to remain shut down. We are in the process of working with Enterprise to wind down operations.

Offshore Texas System

The Offshore Texas System consists of the GIGS and Brazos systems, which have approximately 56 miles of pipeline with diameters ranging from six to sixteen inches and a design capacity of approximately 100 MMcf/d. The Offshore Texas System is in a position to provide gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico offshore Texas. Since 2016, the offshore pipe on both systems was abandoned, and the onshore pipe was out of service. Although we have no ongoing operations, we continue to hold the pipeline asset as we believe it may have potential future value.

Results of operations from the Gas Gathering and Processing Services segment are determined primarily by the volumes of natural gas we gather, process and fractionate, the commercial terms in our current contract portfolio and natural gas, crude oil, NGL and condensate prices. We gather and process natural gas primarily pursuant to the following arrangements:

Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed fee for gathering, processing and transporting natural gas.

Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas liquids and condensate from producers or suppliers at receipt points on our systems at an index price and sell that volume of natural gas liquids or condensate at delivery points on our systems at a higher price versus a comparable price. By entering into purchases and sales of natural gas liquids or condensate on comparable indices, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.

Percent-of-Proceeds Arrangements (“POP”). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas, NGLs and condensate at market prices. Where we provide processing services at the processing plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas. Our POP arrangements also often contain a fee-based component.

Our Gas Gathering and Processing Services assets are located in Alabama, Louisiana, Mississippi and Texas and in shallow state and federal waters in the Gulf of Mexico off the coast of Louisiana and are positioned in areas with opportunities for organic growth. We continually seek new sources of raw natural gas and crude oil supply to maintain and increase the throughput volume on our gathering systems and through our processing plants.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas, natural gas liquids and condensate that flow through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in throughput from producers and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows, but upside in higher commodity-price environments is limited to an increase in throughput from producers. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. For more information see Part II. Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk of this 2018 Form 10-K.

Liquid Pipelines and Services Segment

In our Liquid Pipelines and Services segment, we have the following assets:

Bakken System

The Bakken system is a FERC-regulated crude oil gathering pipeline system that consists of a 47-mile pipeline and related facilities with capacity to transport up to approximately 81,600 Bbl/d of crude oil to the Tesoro Logistics pipeline located Northeast of Watford City, North Dakota and the Energy Transfer Dakota Access Pipeline. The system, which commenced operations in October 2015, provides producers in the area with access to refinery, rail and pipeline markets. The system also has the capability to receive volumes through its truck rack, which also commenced operations in November 2015.

Silver Dollar Pipeline

The Silver Dollar Pipeline located in the Permian Basin and consists of an approximately 186-mile pipeline and related facilities with capacity to transport approximately 125,000 Bbl/d of crude oil. The pipeline was constructed in 2013.

Crude Oil Supply and Logistics (COSL)

Our Marketing business operates around both crude pipeline assets and trucking hubs. We buy and sell crude in North Dakota and Texas to facilitate movements on our pipelines. We have a fleet of 65 crude oil trucks which support West Texas and South Texas.

Cushing

Our crude oil storage facility in Cushing, Oklahoma has an aggregate shell capacity of approximately 3.0 million barrels. We generate crude oil storage revenues by charging customers a fixed monthly fee per barrel of shell capacity that is not contingent on the customer's actual usage of our storage tanks, i.e., take-or-pay firm storage contracts.

Other Systems

Tri-States, Cayenne and Wilprise are also part of the Liquid Pipelines and Services segment and are listed under Investment in Unconsolidated Affiliates below.

Results of operations from the Liquid Pipelines and Services segment are determined by the volumes of crude oil transported on pipelines and related facilities that we own. Our transportation arrangements are further described below:

Committed Shipper Arrangements. Our obligation to provide transportation service to committed shippers means that, pursuant to agreements with the shippers, and subject to applicable tariff provisions, we transport crude oil nominated by shippers in quantities specified in the applicable agreements. In exchange for that obligation on our part, the shipper pays a specified committed shipper rate for quantities of crude actually transported, whether or not the shipper utilizes the capacity.

Uncommitted Shipper Arrangements. Our obligation to provide uncommitted shipper service means that we are only obligated to transport crude oil nominated by shippers to the extent that we have available capacity. For this service the shippers pay an uncommitted shipper rate for quantities actually shipped.

Fee-Based Arrangements. Under these arrangements our operations are underpinned by long-term, fee-based contracts with leading producers in the Midland Basin. Some of these contracts also have minimum volume commitments as well as some have acreage dedications.

Crude Oil Purchase Arrangements. We enter into outright purchase and sales contracts with counterparties, under which contracts we gather and transport different types of crude oil and eventually sell the crude oil to different counterparties. We account for such revenue arrangements on a gross basis.

Natural Gas Transportation Services Segment

In our Natural Gas Transportation Services segment, we have the following assets:

Midla and MLGT Systems

Our Midla system is a FERC-regulated interstate natural gas pipeline comprised of a 52-mile, high pressure 12-inch pipeline (the Midla-Natchez Line) to serve long-standing residential, commercial and industrial customers.

The Mid Louisiana Gas Transmission LLC (“MLGT”) system is an intrastate transmission system that sources natural gas from interconnects with the Florida Gas Transmission (FGT) Pipeline system, the TETCO Pipeline system, the Transco Pipeline system and the Gulf South Pipeline and delivers to various markets including the city of Baton Rouge gas utility, and Louisiana refinery owned and operated by ExxonMobil Corporation and several other industrial customers. Our MLGT-Baton Rouge System is comprised of approximately 65 miles of pipeline with diameters ranging from three to 16 inches.

The northern portion of the MLGT system consists of approximately ten miles of high-pressure pipeline with diameters ranging from six to 16 inches. Natural gas on this system is sourced from Tennessee Gas Pipeline and delivered to multiple power plants operated by Entergy. In addition, the ANGUS Chemical facility was connected in the first half of 2017, increasing the load by approximately 7,000 Mcf/d. The entire MLGT System is connected to six receipt and 28 delivery points.

AlaTenn System

The AlaTenn system is a FERC-regulated interstate natural gas pipeline that interconnects with four major interstate pipelines and travels west to east delivering natural gas to industrial customers in northwestern Alabama. In addition, the AlaTenn System serves numerous loads via North Alabama Gas District, as well as Alabama municipalities such as the cities of Athens, Hartselle, Sheffield and Huntsville. Our AlaTenn System has a design capacity of approximately 200 MMcf/d and is comprised of approximately 294 miles of pipeline with diameters ranging from three to 16 inches and includes two compressor stations with combined capacity of 3,665 horsepower. The AlaTenn System is connected to 59 active delivery and six receipt points, including two interconnects with the Tennessee Gas Pipeline (TGP) system, Texas Eastern Pipeline (TETCO) and the Columbia Gulf Pipeline (CGP). In mid-2017, AlaTenn was connected with the Southern Natural Gas (SONAT) system which provides access to new markets.

Bamagas System

Our Bamagas system is a Hinshaw intrastate natural gas pipeline that travels west to east from an interconnection point with TGP in Colbert County, Alabama, to two power plants in Morgan County, Alabama. The Bamagas System consists of 52 miles of high-pressure, 30-inch pipeline with a design capacity of approximately 450 MMcf/d. Bamagas is connected to two receipt points. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements.

Trigas System

Our Trigas system is located in three counties in northwestern Alabama and has design capacity of approximately 60 MMcf/d and is comprised of approximately 39 miles of pipeline. Our Trigas System has five receipt connections and four delivery connections and currently serves primarily industrial loads.

Magnolia System

The Magnolia system is a Section 311 intrastate pipeline that transports coal-bed methane and receives natural gas from other sources. It is located in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transcontinental Gas Pipe Line Co. pipeline system (Transco), an interstate pipeline owned by The Williams Companies, Inc. The Magnolia system consists of approximately 118 miles of pipeline and trunk lines ranging from six to 24 inches in diameter and four compressor stations with 4,413 horsepower.

Trans-Union

Trans-Union is a 42-mile, 30-inch diameter high-pressure FERC-regulated natural gas interstate pipeline with 546,000 MMbtu/day of maximum capacity. Trans-Union delivers natural gas from Sharon, Louisiana to customers in El Dorado, Arkansas.

Results of operations from the Natural Gas Transportation Services segment are determined by a capacity reservation charge from firm transportation contracts, a variable-use or commodity charge for firm and interruptible transportation contracts, and the volumes of natural gas transported on the interstate and intrastate pipelines we own pursuant to interruptible transportation or fixed-margin contracts. Our transportation arrangements are further described below:

Firm Transportation Arrangements. Our obligation to provide firm transportation service means that, pursuant to the agreement with the shipper, we transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable-use or commodity charge with respect to quantities actually transported by us.

Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that, pursuant to the agreement with the shipper, we only transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a variable-use or commodity charge for quantities actually shipped.

Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

Offshore Pipelines and Services Segment

In our Offshore Pipelines and Services segment, we have the following assets:

High Point System

The High Point system consists of natural gas and liquids pipeline assets located in southeast Louisiana and the shallow water and deep shelf Gulf of Mexico. The High Point System gathers natural gas from both onshore and offshore producing regions around southeast Louisiana. The onshore footprint is in Plaquemines and St. Bernard Parish, Louisiana. The offshore footprint consists of the following federal Gulf of Mexico zones: Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound. Natural gas is collected at more than 63 receipt points that connect to hundreds of wells targeting various geological zones in water depths up to 1,000 feet, with an emphasis on crude oil and liquids-rich reservoirs. The High Point System is comprised of FERC-regulated transmission assets and non-jurisdictional gathering assets, both of which accept natural gas from well production and interconnected pipeline systems. The High Point System delivers the natural gas to various onshore processing plants. The system also includes VKGS, which was purchased from Genesis Energy in June 2017. VKGS consists of natural gas gathering and crude oil gathering lines of various diameter sizes as well as the platform at VK817.

American Panther System (AmPan)

AmPan is comprised of approximately 200 miles of crude oil, natural gas and salt water onshore Texas and offshore Gulf of Mexico pipelines. The system is located in Southern Louisiana and the Gulf of Mexico and has a natural gas design capacity of 475 MMcf/d and crude oil and saltwater capacity of 27 MBbl/d.

Main Pass Oil Gathering System (MPOG)

MPOG is a crude oil gathering system located offshore the Southeast coast of Louisiana in the Gulf of Mexico. The approximately 100-mile system has a total design capacity of approximately 160,000 Bbl/d.

Gloria and Lafitte Systems

The Gloria system is located in Lafourche, Jefferson, Plaquemines, St. Charles and St. Bernard parishes of Louisiana and consists of approximately 138 miles of pipeline, with diameters ranging from three to 16 inches, and two compressors with a combined size of 1,498 horsepower. The Lafitte system consists of approximately 40 miles of gathering pipeline, with diameters ranging from four to 12 inches and a design capacity of approximately 71 MMcf/d. The Lafitte system originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana, at the Alliance Refinery owned by Phillips 66. We are the sole supplier of natural gas to the Alliance Refinery through our Lafitte and Gloria systems. We supply natural gas to the Alliance Refinery pursuant to a long-term contract that expires in 2026.

Quivira System

The Quivira gathering system consists of approximately 47 miles of pipeline, with a 12-inch diameter mainline and several laterals ranging in diameter from six to twenty inches. The system originates offshore of Iberia and St. Mary parishes of Louisiana in Eugene Island Block 24 and can deliver onshore in St. Mary Parish, Louisiana.

Chalmette System

The Chalmette system is located in St. Bernard Parish, Louisiana. The approximate design capacity for the Chalmette System is 125 MMcf/d.

Other Systems

Delta House, Destin and Okeanos are also part of the Offshore Pipelines and Services segment and are discussed under Investments in Unconsolidated Affiliates below.

Results of operations from the Offshore Pipelines and Services segment are determined by capacity reservation fees from firm and interruptible transportation contracts and the volumes of natural gas transported on the interstate and intrastate pipelines we own pursuant to interruptible transportation or fixed-margin contracts. Our transportation arrangements are further described below:

Firm Transportation Arrangements. Our obligation to provide firm transportation service means that, pursuant to the agreement with the shipper, we transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable-use charge with respect to quantities actually transported by us.

Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that, pursuant to the agreement with the shipper, we only transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a variable-use charge for quantities actually shipped.

Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

Terminalling Services Segment

Our Terminalling Services segment consisted of:

Marine Products

Our Marine Products terminals provided storage capacity across three marine terminal sites. The Westwego Terminal site consisted of 48 above-ground storage tanks with a combined capacity of 1,044,600 barrels. The Brunswick Terminal site consisted of one 60,000-barrel above-ground storage tank, two 80,000-barrel above-ground storage tanks and two 500-barrel above-ground storage tanks with a combined capacity of 221,000 barrels. The Harvey Terminal site consisted of 34 above-ground storage tanks with a combined capacity of approximately 1,135,200 barrels. Our Marine Products were sold in the third quarter of 2018.

Refined Products

Our Refined Products terminals provided butane blending capabilities and had aggregate storage capacity of approximately 1.3 million barrels at two refined products terminals located in North Little Rock, Arkansas and Caddo Mills, Texas. Our Refined Products were sold in the fourth quarter of 2018.

Investments in Unconsolidated Affiliates

Delta House

Delta House is a semi-submersible floating production system with associated crude oil and natural gas export pipelines located in the Mississippi Canyon region of the deepwater Gulf of Mexico. The semi-submersible floating production system receives raw production from deepwater wells, which includes a mixture of crude oil, natural gas and produced water, and separates the production into its components. The separated crude oil and natural gas pressures are increased, creating pipeline quality crude oil and natural gas that flows into the respective crude oil and natural gas export pipelines. Delta House is operated by LLOG Exploration Offshore, LLC and has nameplate processing capacity of 80,000 Bbl/d and 200 MMcf/d and peak processing capacity of 100,000 Bbl/d and 240 MMcf/d. Currently, we and ArcLight indirectly own a 35.7% and 23.3% interest, respectively, in Delta House.

Cayenne
On August 8, 2017, we entered into a joint venture agreement with Targa Midstream Services, LLC ("Targa") through our previously wholly owned subsidiary Cayenne. We received $5.0 million in cash in exchange for the sale of 50% ownership interest in Cayenne to Targa. The sole asset of the joint venture is a natural gas pipeline, which has been converted into a natural gas liquids pipeline. Both parties have 50% economic interests and 50% voting rights, with Targa serving as the operator of the pipeline and the joint venture. The additional costs of conversion and associated construction are shared equally by us and Targa. The pipeline became operational on December 28, 2017.

Okeanos

We own a 66.7% operated interest in Okeanos, a 100-mile natural gas gathering system located in the Gulf of Mexico with a total capacity of 1.0 Bcf/d. The Okeanos pipeline connects two platforms and one lateral, terminating at the Destin Main Pass 260 platform in the Mississippi Canyon region of the Gulf of Mexico. Contracted volumes on the Okeanos pipeline are based on life-of-field dedication.

Destin

We own a 66.7% operated interest in Destin, a FERC-regulated, 255-mile natural gas transport system with total capacity of 1.2 Bcf/d. The system originates offshore in the Gulf of Mexico and includes connections with four producing platforms and six producer-operated laterals, including Delta House. The 120-mile offshore portion of the Destin system terminates at the Pascagoula processing plant, owned by Enterprise Products Partners, LP, and is the single source of raw natural gas to the plant. The onshore portion of Destin is the sole delivery point for merchant-quality gas from the Pascagoula processing plant and extends 135 miles north in Mississippi. Destin currently serves as the primary transfer of gas flows from the Barnett and Haynesville Shale plays to Florida markets through interconnections with major interstate pipelines. Contracted volumes on the Destin pipeline are based on life-of-field dedication, dedicated volumes over a given period or interruptible volumes as capacity permits.

Wilprise

We own a 25.3% non-operated interest in Wilprise, a FERC-regulated, approximately 30-mile NGL pipeline that originates at the Kenner Junction and terminates in Sorrento, Louisiana, where volumes flow via pipeline to a Baton Rouge fractionator.

Tri-States

We own a 16.7% non-operated interest in Tri-States, a FERC-regulated, 161-mile NGL pipeline and sole form of transport to Louisiana-based fractionators for NGLs produced at the Pascagoula plant served by Destin and other facilities.

Competition

The midstream business is very competitive, with a number of publicly traded and private equity backed entities servicing the space based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and efficiencies. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for natural gas, crude oil and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis. An increase in competition could result from new pipeline, processing facility, or storage installations or expansions of existing facilities. Major competitors in various aspects of our business include: DCP Midstream LLC; Energy Transfer Partners, L.P.; EnLink NGL Marketing, L.P.; Kinder Morgan Energy Partners LP; Enbridge Inc; Columbia Gulf Transmission Company; Enterprise Gas Processing, LLC; Plains All American Pipeline, L.P.; Medallion Pipeline Company, LLC; Gulf South Pipeline Company, LP; Southern Natural Gas Company; Tennessee Gas Pipeline Company, LLC; Texas Eastern Pipeline; and The Williams Companies, Inc, among others.

Major Customers

See Part II. Item 8. Note 6. Concentration of Credit Risk of this 2018 Form 10-K for a discussion on our significant customers.

Seasonality

See Part II. Item 7. MD&A – Impact of Seasonality of this 2018 Form 10-K for a discussion on seasonality.

Other Segment Information

For additional information on our segments, including revenues from customers, profit or loss and total assets, see Part II. Item 7. MD&A and Part II. Item 8. Note 23. Reportable Segments, of this 2018 Form 10-K.

Regulation of our Operations

Safety and Maintenance

We are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA"), and by the Pipeline Safety Improvement Act of 2002 ("PSIA"), which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in "high-consequence areas," such as high population areas. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. PHMSA also issued its final rule for hazardous liquids pipelines on January 23, 2017. That rule extends regulatory reporting requirements to all liquid gathering lines, requires additional event-driven and periodic inspections, requires use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria and requires certain pipelines to eventually accommodate inline inspection tools. This rule went into effect on March 24, 2017. In March 2016, PHMSA published a notice of proposed rulemaking regarding natural gas pipelines that would amend existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities and extend regulatory requirements to onshore gas gathering lines that are currently exempt. While we cannot predict the outcome of these legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines not previously subject to such requirements. Costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency ("EPA"), community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act ("Superfund") and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety and Superfund

We and the entities in which we own an interest are subject to:

- EPA Chemical Accident Prevention Provisions, also known as the Risk Management Plan requirements, which are designed to prevent the accidental release of toxic, reactive, flammable or explosive materials; and
- Department of Homeland Security Chemical Facility Anti-Terrorism Standards, which are designed to regulate the security of high-risk chemical facilities.

Interstate Natural Gas Pipeline Regulation

Our interstate natural gas transportation systems are subject to the jurisdiction of FERC pursuant to the Natural Gas Act ("NGA"). Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Additionally, costs associated with compliance with these and other FERC regulations and policies could be severe and adversely affect our financial condition, results of operations or cash flow. Federal regulation of our interstate pipelines extends to such matters as:

- rates, services and terms and conditions of service;
- the types of services offered to customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas; and
- participation by interstate pipelines in cash management arrangements.

Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

Section 311 Pipelines

Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce without an exemption under the NGA, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA, and Part 284 of the FERC's regulations. Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis. The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC's review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to comply with applicable FERC regulations for Section 311 service or a FERC-approved statement of operating conditions could result in alteration of jurisdictional status and/or the imposition of administrative, civil and criminal remedies.

Hinshaw Pipelines

Intrastate natural gas pipelines are defined as pipelines that operate entirely within a single state, and generally are not subject to FERC's jurisdiction under the NGA. Hinshaw pipelines, by definition, also operate within a single state, but can receive gas from outside their state without becoming subject to FERC's NGA jurisdiction if (1) they receive natural gas at or within the boundary of a state, (2) all the gas is consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, the FERC issued Order No. 63 authorizing Hinshaw pipelines to apply for authorization to transport natural gas in interstate commerce in the same manner as intrastate pipelines operating pursuant to Section 311 of the NGPA. Hinshaw pipelines frequently operate pursuant to blanket certificates to provide transportation and sales service under the FERC's regulations.

Gathering Pipeline Regulation

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no material adverse effect to our system due to these regulations.

Market Behavior Rules

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, ("EP Act 2005"). Among other matters, the EP Act 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of the EP Act 2005. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. The EP Act 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation which is adjusted periodically for inflation. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

Interstate Oil and Liquids Pipeline Regulation

Our Bakken crude oil gathering system, FERC-regulated American Panther, LLC offshore liquids pipelines (known as the Tiger Shoals and MP 77 offshore pipeline systems) and the Tri-States and Wilprise NGL pipelines, in which we have equity investments, are regulated as common carrier interstate pipelines by the FERC under the Interstate Commerce Act (“ICA”), the Energy Policy Act of 1992 (“EP Act 1992”) and the rules and regulations promulgated under those laws. Under the ICA, FERC has authority regarding the rates and terms and conditions of service for the transportation of oil and natural gas liquids in interstate commerce. The ICA and FERC’s regulations require that rates and terms and conditions of service for interstate service on common carrier pipelines 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 pipelines to file with FERC and publicly post tariffs stating their interstate transportation

rates and terms and conditions of service.
In general, interstate common carrier pipeline rates are initially set through negotiations with non-affiliated shippers or via cost of service ratemaking. In addition, rates can be set via settlement agreed to by all shippers and market-based rates may be permitted in certain circumstances.

Under the ICA, FERC or interested persons may challenge 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. FERC could require a common carrier pipeline to collect rates subject to refund 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 the rate was in effect, if any. 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 filing of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential.

Offshore Pipelines

The Bureau of Ocean Energy Management ("BOEM") manages the exploration and development of the nation's offshore resources. BOEM seeks to appropriately balance economic development, energy independence and environmental protection through crude oil and gas leases, renewable energy development and environmental reviews and studies. The Bureau of Safety and Environmental Enforcement works to promote safety, protect the environment and conserve resources offshore through vigorous regulatory oversight and enforcement.

Sales of Natural Gas and NGLs

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC"), and the Federal Trade Commission ("FTC"). Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Sales of NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

As discussed above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas pipelines and those initiatives may also affect the intrastate transportation of natural gas both directly and indirectly.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for the gathering, compressing, treating and transporting of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying system modification or upgrades during permit reviews;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and
-

enjoining the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations.

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

There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position, results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat and transport natural gas. We cannot assure, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs, and future events may impose costs on our business in excess of our expectations, and may adversely affect our financial condition, results of operations or cash flow. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate little hazardous waste; however, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly disposal requirements.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated soil and groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition. Future contamination may expose us to costs in excess of our expectation, and may adversely affect our financial condition, results of operations or cash flow.

Air Quality and Climate Change

Our operations are subject to the federal Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations and processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, and the requirements are not expected to be more burdensome to us than to any similarly situated company.

A number of states have adopted or considered programs to reduce "greenhouse gases," or GHGs, and the EPA has declared that GHGs "endanger" public health and welfare and is regulating GHG emissions from mobile sources such as cars and trucks. The EPA has also published various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting of requirements of GHGs from petroleum and natural gas systems.

The permitting, regulatory compliance and reporting programs taken as a whole increase the costs and complexity of operating oil and gas operations. This may adversely affect our cost of doing business and demand for the oil and gas we transport. We may also be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Water Discharges

The Federal Water Pollution Control Act ("Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill Prevention Control and Countermeasure ("SPCC") requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flow.

Safe Drinking Water Act

The underground injection of crude oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. As of December 31, 2018, the Partnership is in compliance with the requirements.

Anti-terrorism Measures

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

Title to Properties and Rights-of-Way

Our real property falls into two categories: i) parcels that we own in fee and ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remaining land on which our plant sites and major facilities are located, are held by us pursuant to surface leases. easements, rights of way, permits or licenses between us and the fee owner of the lands. Our predecessors leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Employees

The Partnership does not have any employees. All of the employees required to conduct and support our operations are employed by our General Partner, and the officers of our General Partner manage our operations and activities. As of December 31, 2018, our General Partner employed approximately 480 people who provide direct, full-time support to our operations. None of these employees are covered by collective bargaining agreements, and our General Partner considers its employee relations to be positive.

General

We make certain filings, and amendments thereto, with the Securities and Exchange Commission (the "SEC"), including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports. All of these filings are available as soon as reasonably practicable after the electronic filing with the SEC free of charge on our website, www.americanmidstream.com. Additionally, the filings are available on the Internet at www.sec.gov. We intend to use our website as a means for disseminating information in accordance with Regulation FD under the Exchange Act. The information contained on our website is not part of, nor is it incorporated by reference into, this 2018 Form 10-K.

Item 1A. Risk Factors

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this 2018 Form 10-K, including Part I. Item 1. Business – Regulation of Business, in evaluating an investment in our common units. The risks described below are not the only ones that we face. Additional risks not presently known to us or that we currently deem immaterial individually or in the aggregate may also impair our business operations.

If any of these risks were to occur, our business, financial condition, results of operations or cash flows could be materially adversely affected. We may not be able to achieve some or all of our stated business strategies or realize our stated strengths. In that case, the trading price of our common units could decline and you could lose all or part of your investment in us.

This 2018 Form 10-K also contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of various factors, including the risks and uncertainties faced by us described below. Please read our "Cautionary Statement About Forward Looking Statements" in this 2018 Form 10-K.

Risks Related to our Business

Our current and future indebtedness levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2018, we had approximately $1.0 billion in principal amount of debt outstanding and $39.8 million of borrowing commitment available to us under our revolving credit facility. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for, and reacting to, changes in our business, including possible acquisition opportunities and prohibit us from declaring and making cash distributions to our unitholders;
- 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 principal and interest payments on our indebtedness;
- our indebtedness level may make us more vulnerable than our competitors with less debt 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.

Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to make cash distributions to our unitholders.

Our ability to service our indebtedness will depend 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 our current or future indebtedness, we will be forced to take actions such as reducing distributions to our unitholders, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms, or at all.

We have identified material weaknesses in our internal controls at December 31, 2018, and we have been unable to remediate the material weaknesses identified in 2016 and 2017. If we fail to remediate these material weaknesses or otherwise fail to develop, implement and maintain appropriate internal controls in future periods, our ability to report our financial condition and results of operations accurately and on a timely basis could be adversely affected.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

We did not maintain an effective control environment as we lacked sufficient oversight of activities related to our internal control over financial reporting and had an insufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with our financial reporting requirements. This material weakness contributed to additional material weaknesses, as the Partnership did not design and maintain effective controls over: verifying that complex, non-routine transactions were recorded appropriately; all financial statement assertions of revenues and receivables, specifically the review of the accounting for certain contracts, the review that price, volume and other key contractual terms used to record revenue are consistent with the terms of the arrangement and the review that revenue is recorded in the proper period; all financial statement assertions related to acquisitions and divestitures, specifically verifying the existence, rights and obligations associated with assets acquired and liabilities assumed, reviewing the valuation of the purchase price allocation and reviewing the completeness and accuracy of related disclosures; the period-end financial reporting process, specifically verifying the review of journal entries are performed by individuals separate from the preparer and that the journal entries are complete, accurate and property supported, and the review of account reconciliations and financial statement analysis to support all financial statement assertions of the consolidated financial statements and disclosures; and the accuracy and valuation of asset retirement obligations, goodwill, other intangible assets and finite-lived assets, specifically the review of the model, data, assumptions and calculations used in determining the estimated asset retirement obligation and in impairment tests, and the related identification of changes in events and circumstances that indicate it is more likely than not that an impairment indicator has occurred. Additionally, we did not maintain effective controls over certain information technology ("IT") general controls for applications used in the preparation of our consolidated financial statements. Specifically, we did not maintain user access controls to ensure appropriate segregation of duties and adequate restriction of user and privileged access to the financial application, programs, and data to appropriate Partnership personnel. These IT deficiencies did not result in a material misstatement to the consolidated financial statements, however, the deficiencies, when aggregated, could impact our ability to maintain effective segregation of duties, as well as maintain effective IT-dependent controls which could result in misstatements of substantially all of the financial statement accounts and disclosures resulting in a material misstatement to the annual or interim consolidated financial statements that otherwise would not be prevented or detected. Accordingly, our management determined that, as of December 31, 2018, our disclosure controls and procedures and our internal control over financial reporting were not effective. The specific material weaknesses and our remediation efforts are described in Part II, Item 9A - "Controls and Procedures" of this 2018 Form 10-K.

We are in the process of remediating the identified material weaknesses in our internal controls, but we are unable at this time to estimate when, or if, the remediation effort will be completed. During the course of implementing additional processes and controls, as well as controls operating effectiveness testing, we may identify additional control deficiencies, which could give rise to other material weaknesses, in addition to the material weaknesses described above. As we continue to evaluate and work to improve our internal control over financial reporting, we may determine to take additional measures to address these material weaknesses or modify certain of the remediation measures. Further and continued determinations that there are material weaknesses in the effectiveness of our internal controls could reduce our ability to obtain financing or could increase the cost of any financing we obtain and require additional expenditures of resources to comply with applicable requirements.

Prior to our entry into the Waiver, the existence of a qualification in our audited financial statements may have constituted an event of default under the Credit Agreement. Pursuant to the Waiver, the administrative agent and certain lenders (as required by the Credit Agreement) have waived the Financial Statements Audit Requirement for the fiscal year ended December 31, 2018. Although we entered into the Waiver to address the event of default possibly arising pursuant to the existence of a going concern note and material weakness exception in our audited financial statements contained in this Form 10- K, there is no guarantee that our lenders will agree to waive events of default or potential events of default in the future. For additional discussion of the Waiver, see Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. Overview - Amendment to Credit Agreement.

The indenture governing our senior notes and our credit facility contain certain financial covenants and ratios and other restrictions. We have had, and may continue to have, difficulty maintaining compliance with such financial covenants and ratios and other restrictions, which could adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

We are dependent upon certain earnings and cash flow generated by our operations in order to meet our debt service obligations. We also depend on our Credit Agreement (as defined below) for working capital and future expansion capital needs and, as necessary, to fund a portion of cash distributions to unitholders. The indenture governing the notes and our revolving credit facility contain, and any future financing agreements may contain, operating and financial restrictions and covenants that could restrict our ability to finance future operations or capital needs, or to expand or pursue our business activities, which may, in turn, limit our ability to pay distributions to our unitholders. For example, our revolving credit facility limits our ability to, among other things:

- declare or make cash distributions on our common units and preferred units;
- incur or guarantee additional indebtedness;
- make certain investments and acquisitions;
- redeem or repay other debt or make other restricted payments, including cash distributions to our unitholders;
- enter into certain types of transactions with affiliates;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- enter into sale and leaseback transactions;
- merge or consolidate with another company;
- transfer, sell or otherwise dispose of assets, including equity interests in our subsidiaries;
- use proceeds from certain asset sales for any purpose other than repaying indebtedness under the credit facility; and
- cancel or modify material contracts.

On March 8, 2017, we along with certain of our subsidiaries (collectively, the “Borrowers”), entered into the Second Amended and Restated Credit Agreement, with Bank of America N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders (the “Original Credit Agreement”).

During 2018, we amended the Original Credit Agreement by entering into the First Amendment on June 29, 2018 and by entering into the Second Amendment on December 27, 2018 with a syndicate of lenders and Bank of America, N.A., as administrative agent.

We entered into the Amendments to, among other things, revise certain financial covenants to remain in compliance with the terms of the Credit Agreement. Absent the Amendments, we would not have been in compliance. As amended, we are in compliance with the Credit Agreement but may not be able to remain compliant with the Credit Agreement and may not be able to obtain necessary waivers or amendments from lenders to maintain compliance in the future.

As amended, the Credit Agreement contains certain terms and financial covenants, including:

	Minimum Consolidated Interest Coverage Ratio	Maximum Consolidated Total Leverage Ratio	Maximum Consolidated Secured Leverage Ratio
December 31, 2018	1.75:1.00	6.25:1.00	3.75:1.00
March 31, 2019	1.75:1.00	6.50:1.00	3.75:1.00
June 30, 2019 and thereafter	1.50:1.00	5.75:1.00	3.50:1.00

Our ability to comply with these covenants and ratios in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of the financial markets, commodity price levels, disruptions in operations of our or our joint ventures' assets and our ability to sell assets for adequate proceeds.

Our Credit Agreement currently prohibits us from declaring or making cash distributions to our unitholders until our consolidated total leverage ratio is reduced to less than 5.00:1:00.

As a result of the Second Amendment, we are not permitted to declare or make any cash distributions to our unitholders until our consolidated total leverage ratio is reduced to less than 5.00:1.00, as shown in the compliance certificate required to be delivered together with audited consolidated financial statements for the most recently completed fiscal year and consolidated unaudited financial statements for the most recently completed quarter. Therefore, the Credit Agreement prohibited us from making any cash distributions on our common units with respect to the fourth quarter of 2018, and we do not expect to make any distributions on our common units with respect to the first quarter of 2019. We will not be permitted to make any cash distributions for future quarters until our consolidated total leverage ratio is reduced to less than 5.00:1.00.

We do not plan to pay distributions on our common units through the completion of the Pending Merger. We may not have sufficient cash from operations to enable us to pay distributions to holders of our common units.

Even if we planned to pay distributions and we were not prohibited contractually from paying cash distributions to our unitholders, we may not have sufficient available cash from operations each quarter to enable us to pay the minimum quarterly distribution on our common units or at all. These distributions may only be made from cash available for distribution after the quarterly distribution to which our convertible preferred units are entitled, the establishment of cash reserves, and payment of our fees and expenses. 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 a variety of factors, including any of the business risks and uncertainties described or referenced in this Item 1A.

While ArcLight has provided certain cash contributions to us in the past, it was and is under no contractual obligation to do so. Such support is not expected to be provided in the future.

There is no guarantee that unitholders will receive quarterly distributions from us. Our distributions are determined each quarter by the Board based on their consideration of the foregoing factors, our financial position, earnings, cash flow, current and future business needs and other relevant factors at that time. For example, in July 2018, as part of a revised capital allocation strategy, we reduced our quarterly distribution per common unit to 25% of the minimum quarterly distribution. For the fourth quarter of 2018, we did not pay any quarterly distribution on our common units, and through the completion of the Pending Merger, we do not expect to pay a quarterly distribution on our common units.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses for financial reporting purposes and may not make cash distributions during periods when we record net income for financial reporting purposes.

Any decrease in the volumes of natural gas, NGLs or crude oil that we or our joint ventures gather, process or transport could adversely affect our business and operating results.

The volumes that support our business are dependent on the level of production from natural gas and crude oil wells connected to our systems, including volumes from significant customers, the production of which will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas and crude oil. The primary factors affecting our ability to obtain non-dedicated sources of natural gas and crude oil include (i) the level of successful drilling activity in our areas of operation and (ii) our ability to compete for volumes from successful new wells.

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production.

Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. Certain of our operating costs and expenses are fixed and do not vary with the volumes we transport or redeliver. These costs and expenses may not decrease ratably or at all should we experience a reduction in the volumes we sell, transport or redeliver. If commodity prices decreased or if producers experienced sustained curtailment of production, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants in our revolving credit facility.

Reduced profitability may also result in future non-cash impairments of long-lived assets, goodwill, or intangible assets.

Because of these and other factors, even if new natural gas, NGL and crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

Natural gas, crude oil, NGL and other commodity prices are volatile, and a reduction in these prices in absolute terms, or an adverse change in the prices of natural gas and NGLs relative to one another, could affect the demand for natural gas, NGLs or condensate and could adversely affect our net income and cash flow.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. Volatility in commodity prices could affect the demand for our services.

Natural gas and crude oil prices declined dramatically in late 2015 and have fluctuated since 2016. In the second half of 2018, crude oil prices declined dramatically. For instance, the NYMEX-WTI oil price declined from $60.37 per Bbl on January 2, 2018 to $45.41 per Bbl on December 31, 2018. The prices of natural gas and crude oil may continue to be volatile as a result of various factors, such as, the supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- worldwide economic conditions and political events, including actions taken by foreign oil and gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes;
- the levels of world-wide and domestic production and consumer demand;
- the availability of imported, or market for exported, crude oil and liquefied natural gas, or LNG;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;
- the nature and extent of governmental regulation and taxation; and
- the current and anticipated future prices of natural gas, crude oil, NGLs and other commodities.

These economic conditions, in addition to extended periods of ethane rejection, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of natural gas processing and transportation capacity and government regulations could affect prices and production levels of natural gas, NGLs and condensate. A decrease in demand for natural gas, NGLs or condensate could decrease volumes and adversely affect the margin and profitability of our midstream business.

Our growth strategy, and ability to fund expansion capital projects, requires access to new capital. Our ability to access the capital markets, tightened capital markets or other factors that increase our cost of capital, or limit our access to capital, could impair our ability to grow.

We continuously consider potential acquisitions and opportunities for expansion capital projects. Acquisition opportunities arise quickly and unexpectedly, may occur at any time and may be significant in size relative to our existing assets and operations. Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. Limitations on our access to capital or increase in the cost of that capital has impaired, and could continue to significantly impair, our growth strategy. Our ability to maintain our targeted credit profile, including our target debt-to-equity ratio, has affected, and could continue to affect, our cost of capital as well as our ability to execute our growth strategy. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets.

Market demand for securities issued by master limited partnerships, especially common units, has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our expansion capital expenditures and acquisition capital expenditures with the issuance of new securities. Furthermore, because we filed our 2017 Form 10-K after the applicable deadline, we have not been eligible to use Form S-3 for the last eleven months and will not be eligible again until at least May 1, 2019. This may limit or delay our access to the public capital markets.

Due to these factors, we cannot be certain that funding for our capital needs will be available from bank credit arrangements, our revolving credit facility or capital markets on acceptable terms, or at all. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plans, enhance our existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Our business is subject to a number of weather related risks, including severe weather in the U.S. Gulf of Mexico, which can cause significant damage and disruption to our business interests located in that region.

The U.S. Gulf of Mexico experiences hurricanes and other extreme weather conditions on a frequent basis, the frequency of which may increase with climate change. Our High Point system, our Offshore Texas system, our Destin system, our Okeanos system, our MPOG system and non-operated interests Delta House and any future systems that we acquire in the U.S. Gulf of Mexico, are susceptible to adverse weather conditions in the U.S. Gulf of Mexico, including hurricanes and other extreme weather conditions. Our insurance and weather derivatives may not cover all associated loss. High winds, storm surge, and turbulent seas can cause significant damage and curtail these operations for extended periods during and after such weather conditions, which may result in decreased revenues from our interests in these operations. In addition, these adverse weather conditions in the U.S. Gulf of Mexico can affect producers connected to our facilities even if our facilities are not damaged, which may result in decreased revenues from our interests in these operations. As we execute our revised capital allocation strategy, we intend to divest non-core onshore assets, which will increase the significance of weather-related disruptions to our operations in the Gulf of Mexico.

To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

We are subject to the risk of loss resulting from nonpayment or nonperformance by our customers and counterparties in the ordinary course of our business.

We are subject to the risk of loss resulting from nonpayment or nonperformance by our customers and counterparties in the ordinary course of our business. Additionally, this risk may increase as a result of our revised capital allocation strategy as we divest certain non-core assets, which may concentrate our customer base. Generally, we either consider our customers creditworthy or require those who are not creditworthy to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies will not completely eliminate customer and counterparty credit risk. Our customers and counterparties include entities whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities.

In addition, in connection with the acquisition of certain of our assets, we have entered into agreements pursuant to which various counterparties have agreed to indemnify us, subject to certain limitations, for certain matters arising from the pre-closing ownership and operation of assets.

The low commodity price environment in prior years negatively impacted many oil and gas companies causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts, and this could recur. To the extent one or more of our key customers or counterparties commences bankruptcy proceedings, our contracts with such customers or counterparties may be subject to rejection under applicable provisions of the United States Bankruptcy Code or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, results of operations, cash flows and financial conditions. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness and any resulting increase in nonpayment or nonperformance by them could cause us to write down or write off accounts receivable. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution could be adversely affected.

Our natural gas gathering and processing and transportation systems connect to other pipelines or facilities, the majority of which are owned and operated by third parties. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities and others upon which we rely may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. For example, the explosion and fire at the Pascagoula Gas plant in June of 2016 suspended operations from that facility for over eight months. Additionally, infrastructure remediation work on Delta House during 2018 resulted in a temporary curtailment of production flow, causing a reduction in earnings from unconsolidated affiliates. If any of these pipelines or other midstream facilities becomes unable to receive or transport natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution may be adversely affected.

Our operations are subject to laws and regulations, including environmental laws and regulations relating to climate change and greenhouse gas emissions, which may restrict our operations or expose us to significant costs, liabilities, and expenditures that could exceed our expectations.

The natural gas sales, transportation, and storage operations of our gas pipelines are subject to regulation by the FERC and other federal, state, and local regulatory authorities. Regulatory or administrative actions by these regulatory authorities can affect our business in many ways, including decreasing revenues, decreasing volumes in our pipelines, increasing our costs, and otherwise altering the profitability of our business. The operation of our businesses might also be adversely affected by regulatory proceedings, changes in government regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in the proposal and/or implementation of increased regulations. Such scrutiny has also resulted in various inquiries, investigations, and court proceedings, including litigation of energy industry matters. Additionally, certain inquiries, investigations, and court proceedings are ongoing. We cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines and/or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of our business and our results of operations or increase our operating costs in other ways.

In addition, climate change regulations and the costs associated with the regulation of emissions of greenhouse gases ("GHGs") have the potential to affect our business. Regulatory actions by the Environmental Protection Agency or the passage of new climate change laws or regulations could result in increased costs to operate and maintain our facilities, install new emission controls on our facilities, or administer and manage our GHG compliance program. New climate change regulation could have a material adverse effect on our results of operations and financial condition.

The result of the laws and regulations affecting our business, or the imposition or proposal of new laws and regulations affecting our business, either individually or in the aggregate, could be material and could adversely affect our results of operations. For a detailed discussion of these matters as they may impact the regulations affecting our business, see Item 1. Business. Regulation of Operations.

A significant portion of our cash flows come from our joint ventures in which we often hold a non-controlling minority ownership position. We may experience reductions in cash flows from our joint ventures due to contractual step-downs in cash distributions, operational or other issues that are beyond our control. We may acquire similar non-controlling minority ownership positions in joint ventures in the future.

We own a 50% membership interest in Cayenne and minority interests in Delta House, Wilprise and Tri-States. We do not control these projects or joint ventures or their governing boards. As a result, our ability to pay cash distributions to our unitholders will depend in part on factors beyond our control, such as the performance of these projects or joint ventures and their distributions of cash to us. Cash distributions to us may be reduced or suspended if the assets comprising the businesses of these projects or joint ventures, or the assets of their customers, are adversely impacted by operational hazards.

For example, in 2018, due to an unplanned operational disruption beyond our control, we experienced a substantial reduction in cash distributions from Delta House. Curtailment of operations at Delta House, including the unplanned operational disruption, negatively impacted distributions from Delta House by approximately $34.0 million in 2018. Although ArcLight has offset some of these reduced distributions in the past, it may not offset reductions from Delta House, or other joint ventures, in the future.

Distributions from Delta House are directly correlated to production volumes, such that a 10% change in production volumes would impact expected distributions by approximately 9%. However, under the terms of the operating agreement for Delta House, the portion of Delta House's total distributions that we are entitled to receive declines once cumulative production processed by the platform exceeds a specific cumulative production hurdle. Once this threshold is reached, the rate charged by Delta House FPS drops from $4.50 per BOE to $1.50 per BOE, or a 67% decrease. Assuming no operational disruptions that significantly impact production volumes in 2019, we expect this rate reduction, which could reduce our net income, to take effect as early as 2020. There are no cumulative rate changes associated with the portion of distributions associated with the Delta House OGL, however a fixed component totaling $21.6 million annually, of which, approximately $7.7 million represents our prorated interest, will expire in July 2022.

Further, additional projects we may acquire may be subject to a similar structure where we do not own a majority of the project or project entity and we may invest in joint ventures in which we share control or in which we are a minority investor. In these instances, the majority investor or controlling investor may not have the level of experience, technical expertise, human resources management and other attributes necessary to operate these assets optimally.

This risk may be magnified as we execute our revised capital allocation strategy and divest certain non-core assets, which may increase the proportion of cash provided by entities we do not control.

We depend on a relatively small number of customers for a significant portion of our gross margin. The loss of any one of these customers could adversely affect our ability to make distributions.

A significant percentage of the gross margin in each of our segments is attributable to a relatively small number of customers. Additionally, a number of customers upon which our business depends are small companies that may have limited access to capital or that may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better capitalized companies. Although we have gathering, processing and transmission contracts with significant customers of varying duration and commercial terms, if one or more of these customers were to default on their contract or if we were unable to renew our contract with one or more of these customers on favorable terms, we may not be able to replace these customers in a timely fashion, on favorable terms or at all. In any of these situations, our gross margin and cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross margin.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.

We compete with other midstream companies in our areas of operation. In addition, some of our competitors are large companies that have greater financial, managerial and other resources than we do. Our competitors may expand or construct gathering, compression, treating, processing or transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers may develop their own gathering, compression, treating, processing or transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our gathering, processing, transportation and terminal contracts subject us to renewal risks.

We gather, purchase, process, transport and sell most of the commodities on our systems under contracts with terms of various durations, including contracts that have terms as short as one month or which are cancellable on as little as 30 days’ notice, and which may be difficult to extend or replace. We provide NGL sales and distribution services, refined products terminals, crude oil pipeline services and above-ground storage services that support various commercial customers. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with percent-of-proceeds contracts may choose to switch to fee-based gathering and transportation contracts, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenue, gross margin and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected.

The value of our interests in operations located in the U.S. Gulf of Mexico could be adversely impacted by increased regulation and continuing regulatory uncertainty.

Operations in the U.S. Gulf of Mexico have been subject to an increasingly stringent regulatory environment including government regulations focused on offshore operating requirements, spill cleanup, and enforcement matters. These regulations also implement additional safety and certification requirements applicable to offshore activities in the U.S. Gulf of Mexico. Certain operating assets such as our High Point system, Destin system, Okeanos system and our Offshore Texas system, and certain non-operated interests in operations located in the U.S. Gulf of Mexico that we currently hold or may hold in the future, are subject to such increased regulations, including our non-operated interests in Delta House. In addition, the Bureau of Safety and Environmental Enforcement and the Bureau of Ocean Energy Management has increased regulatory activity including shortening the time period a line may be inactive before it must be removed or abandoned and requiring additional supplemental bonding or other forms of providing abandonment security for offshore facilities on the Outer Continental Shelf. These new regulations have increased our operating costs, and the operating costs of our producer customers. As a result, the value of our interests in these operations may be adversely affected by these regulations. Future regulatory requirements could delay activities from these operations and reduce our revenues, resulting in reduced cash flows and profitability. Moreover, any failure to satisfy these regulatory requirements by our producing customers could result in the commencement of enforcement proceedings or the taking of other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, could materially reduce the demand for our services. This risk may be magnified as we divest certain non-core assets as part of our capital reallocation strategy, which may increase the impact of regulation in the U.S. Gulf of Mexico on our total business.

Significant portions of our pipeline systems have been in service for several decades and we have a limited ownership history with respect to all of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Significant portions of the pipeline systems that we have purchased had been in service for many decades prior to our purchase. Consequently, our executive management team has a limited history of operating such assets. There may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

A downgrade in our credit ratings could impact our access to capital and costs of doing business, and maintaining credit ratings is under the control of independent third parties.

Rating agencies may reevaluate our ratings, and any additional actual or anticipated downgrades in such credit ratings could limit our ability to access credit and capital markets, including to refinance our existing revolving credit facility, or to restructure or refinance our other indebtedness. On November 1, 2017, S&P and Moody’s both announced that our long term credit rating had been placed on watch as a result of the announcement of the SXE Transactions. On May 7, 2018, Moody's downgraded our liquidity rating from SGL-3 to SGL-4. On July 31, 2018, Moody's announced that it had concluded its previously announced review and changed its outlook for us to negative and concurrently upgraded our liquidity rating from SGL-4 to SGL-3. As a result of these actions, future financing or refinancing, may result in higher borrowing costs and require more restrictive terms and covenants, including obligations to post collateral with third parties, which may further restrict our operations and negatively impact liquidity.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

If we are unable to repay, extend or refinance our existing and future debt as it becomes due on terms reasonably acceptable to us, or at all, we may be unable to continue as a going concern.

Absent any action with respect to the repayment or refinancing of our existing indebtedness or any waivers or amendments to the agreements governing our existing indebtedness, our Credit Agreement is scheduled to mature on September 5, 2019. Although we are actively engaged with the Credit Agreement lender group, we may not be able to extend, replace or refinance our existing Credit Agreement on terms reasonably acceptable to us, or at all, with our current lender group or with replacement lenders. If we are able to obtain replacement financing, it may be more costly or on terms more burdensome than our current Credit Agreement. In addition, we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding under our Credit Agreement upon its maturity. As renewal or refinance of the Credit Agreement remains uncertain, the audited financial statements contained in this Form 10-K include a note regarding our ability to continue as a going concern. Although we entered into the Waiver to address the existence of a going concern note and material weakness exception in the audited financial statements contained in this Form 10-K and to extend the Financial Statements Delivery Deadline to April 30, 2019, the Waiver does not waive any default or event of default other than in connection with the Financial Statements Audit Requirement and Financial Statements Delivery Deadline. There is no guarantee that our lenders will agree to waive events of default or potential events of default in the future. Moreover, such issues and waivers divert the attention of management from our operations and require the Partnership to incur certain fees and expenses.

If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the Credit Facility or other agreements governing our indebtedness, an event of default could result, which could permit acceleration of such debt and acceleration of our other debt. Any accelerated debt would become immediately due and payable, and we may be unable to continue as a going concern. For additional discussion of the Waiver, see Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. Overview - Amendment to the Credit Agreement.

In connection with our expansion capital programs, we have agreed, and may in the future agree, to construct oil and gas gathering pipelines to service existing and future oil and gas properties, which involves potential risks.
In connection with our expansion capital programs, we have agreed, and may in the future agree, at our cost and expense, to design, acquire right-of-way for, obtain all permits from governmental authorities for, procure materials for, construct, operate, and maintain additional gathering pipelines for connection to certain current and future producing crude oil and natural gas properties. There are risks involved with such obligations, including:

- general construction cost overruns and delays resulting from numerous factors, many of which may be out of our control;
- the inability to obtain required permits for the pipelines;
- the inability to obtain rights-of-way for the gathering pipelines, which may result in pipelines being re-routed, which itself could result in cost overruns and delays;
- the risk associated with producer’s exploration and production activities and the associated potential failure of the gathering pipelines to generate attractive cash flows given our obligation to construct and operate them; and
- title issues or environmental or regulatory compliance matters or liabilities or accidents associated with the construction or operation of the pipelines.

We currently expect to fund these costs with borrowings under our revolving credit facility or by accessing the capital markets. If we are unable to finance the expansion costs with existing liquidity, we could be required to seek alternative sources of liquidity, which could be costly or may not be available. In the event expansion and extension of the crude oil and natural gas properties is significantly more expensive than we expect, or we are unable to obtain financing for such construction, it could have a material adverse effect on our financial condition, including our results of operations and cash flows.
Our business involves many hazards, operational risks and litigation risks, some of which may not be fully covered by insurance. If a significant accident, event or judgment occurs for which we are not adequately insured, our operations and financial results could be adversely affected.
Our operations are subject to all of the risks and hazards inherent in the gathering, compressing, treating, processing and transportation of natural gas, including:

- damage to pipelines, plants, storage facilities, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires, earthquakes and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution, hurricanes or other environmental damage. These risks may also result in curtailment or suspension of our operations. For example, in 2017, Hurricane Harvey hit the Texas Gulf Coast, disrupting our operations and negatively impacting our financial results. In addition, we have been, and are likely to continue to be, a defendant in various legal proceedings and litigation arising in the ordinary course of business, both as a result of these operating hazards and risks and as a result of other aspects of our business. For example, we have been the subject of a number of land-related litigation matters in Louisiana, which are immaterial in amount but still involve expenses and attention of personnel. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations.
We are not fully insured against all risks inherent in our business. For example, we do not have any casualty insurance on our underground pipeline systems that would cover damage to the pipelines. We are self-insured for general and product, workers’ compensation and automobile liabilities up to predetermined amounts above which third-party insurance applies. Additionally, we do not have business interruption/ loss of income insurance that would provide coverage in the event of damage to any of our underground facilities. In addition, coverage for hurricane damage is

very limited, and although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. We cannot guarantee that our insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage. If a significant accident or event occurs for which we are not fully insured, it could have a material adverse effect on our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our contractual indemnification rights for potential environmental liabilities.

We may be unable to obtain or renew permits necessary for our operations or the operations we may acquire in future acquisitions.

Our facilities operate under a number of required 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. All of these permits, licenses, approvals, limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval, limit or standard. Noncompliance or incomplete documentation of our compliance status 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 material permit, license or approval, or to revoke or substantially modify an existing permit, license or approval, could have a material adverse effect on our financial condition, including our results of operations and cash flows.

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

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate or do not allow us to change our operations, or we may not be able to renew our contract leases on commercially reasonable terms or at all. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time for specific types of operations. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise or our inability to amend these rights for new operations, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

A failure in our operational systems or cybersecurity attacks on any of our facilities, or those of third parties, may adversely affect our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings or downtime, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operational departments, and these systems may subject our business to increased risks. As of December 31, 2018, we did not maintain effective controls over certain information technology general controls for a significant application used in the preparation of our consolidated financial statements. Any future cybersecurity attacks that affect our facilities, our customers and any financial data, including as a result of our inability to adequately restrict user and privileged access to our financial application, programs and data, could have a material adverse effect on our business. In addition, cyber-attacks on our financial, customer and employee data may result in financial loss and may negatively impact our reputation. We may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security, and additional security personnel. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results. Moreover, the costs associated with addressing or preventing cyber breaches or complying with new regulations may be substantial.

Terrorist attacks and the threat of terrorist attacks may adversely impact our results of operations.

Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding terrorist attacks in the U.S. may affect our operations in unpredictable ways, including disruptions of crude oil supplies or storage facilities, and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Risks Related to the Pending Merger

We may be unable to obtain the regulatory clearances required to complete the Pending Merger or, in order to do so, we may be required to comply with material restrictions or satisfy material conditions.

Even though approval under the HSR Act is not required, the Pending Merger may still be reviewed under antitrust statutes of other governmental authorities, including by state regulatory authorities such as the MPSC. The closing of the Pending Merger is subject to the condition that there is no law, injunction or other legal restraint in effect prohibiting, and no governmental authority is seeking a restraint to prohibit, consummation of the transaction contemplated under the Merger Agreement. We can provide no assurance that all required regulatory clearances will be obtained. If a governmental authority asserts objections to the Pending Merger, we may be required to divest assets in order to obtain antitrust clearance. There can be no assurance as to the cost, scope or impact of the actions that may be required to obtain antitrust or other regulatory approval. If we take such actions, it could be detrimental to it or to the combined organization following the consummation of the Pending Merger. Furthermore, these actions could have the effect of delaying or preventing the closing of the Pending Merger or imposing additional costs on our business during the pendency of the Pending Merger.

State attorneys general could seek to block or challenge the Pending Merger as they deem necessary or desirable in the public interest at any time, including after completion of the transaction. In addition, in some circumstances, a third party could initiate a private action under antitrust laws challenging or seeking to enjoin the Pending Merger, before or after it is completed. We may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

We may have difficulty attracting, motivating and retaining employees in light of the Pending Merger.

Uncertainty about the effect of the Pending Merger on our employees may have an adverse effect on the combined organization, particularly given we will no longer be part of a publicly traded entity. This uncertainty may impair our ability to attract, retain and motivate personnel until the Pending Merger is completed. Employee retention may be particularly challenging during the pendency of the Pending Merger, as employees may feel uncertain about their future roles with the combined organization. In addition, we may have to provide additional compensation in order to retain employees, which will increase our administrative expenses even if the Pending Merger does not close. If our employees depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined organization, we could experience adverse disruption in our business.

We are subject to business uncertainties and contractual restrictions relating to the Pending Merger, which could adversely affect our business and operations.

In connection with the Pending Merger, it is possible that some customers, suppliers and other persons with whom we have business relationships may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship with us, which could negatively affect our revenues, earnings and cash available for distribution, as well as the market price of our common units, regardless of whether the Pending Merger is completed.

Under the terms of the Merger Agreement, we are subject to certain restrictions on the conduct of our business prior to completing the Pending Merger, which may adversely affect our ability to execute certain of our business strategies. Such limitations could negatively affect our business and operations prior to the completion of the Pending Merger. For a discussion of the Pending Merger and the Merger Agreement, see Item 1. Business. Pending Merger.

The Pending Merger is subject to conditions, including certain conditions that may not be satisfied on a timely basis, if at all. Failure to complete the Pending Merger, or significant delays in completing the Pending Merger, could negatively affect the trading price of our common units and our future business and financial results.

The completion of the Pending Merger is subject to a number of conditions. The completion of the Pending Merger is not assured and is subject to risks, including the risk that approval by governmental agencies is not obtained or that other closing conditions are not satisfied. If the Pending Merger is not completed, or if there are significant delays in completing the Pending Merger, the trading price of AMID common units and our future business and financial results could be negatively affected, and we will be subject to several risks, including the following:

- we may be liable for damages to Proposed Parent under the terms and conditions of the Merger Agreement;
- negative reactions from the financial markets, including declines in the price of AMID common units due to the fact that current prices may reflect a market assumption that the Pending Merger will be completed; and

- the attention of our management will have been diverted to the Pending Merger rather than our own operations and pursuit of other opportunities that could have been beneficial to us.

We will incur substantial transaction-related costs in connection with the Pending Merger.
We expect to incur a number of non-recurring transaction-related costs associated with evaluating and completing the Pending Merger. These fees and costs will be substantial regardless of whether the Pending Merger is completed. Non-recurring transaction costs include, but are not limited to, fees paid to financial, legal and accounting advisors, filing fees and printing costs. Additional unanticipated costs may be incurred in preparation for the integration of our business with the business of the Proposed Parent. We will not recover these costs if the conditions to closing the Pending Merger are not satisfied, which would have an adverse impact on our financial condition as a stand alone business.

The Pending Merger involves a conflict of interest between ArcLight and the Partnership.

ArcLight has no duty under the Partnership Agreement to the Partnership or its unitholders and may act in its own best interest or the interest of its partners in connection with the Pending Merger, including making the proposal, negotiating the Pending Merger and voting its affiliates' units in favor of the Pending Merger. Under the Partnership Agreement, the Pending Merger is required to be approved by a majority of the outstanding common units and preferred units, voting as a class, and each class of preferred units. Affiliates of ArcLight own approximately 51% of such voting power and prior to the execution of the Merger Agreement, affiliates of ArcLight delivered to the Partnership a written consent approving the Pending Merger. As such, the Pending Merger has been approved by the limited partners of the Partnership, and the Partnership will not hold a meeting of its unitholders to approve the merger.

Risks Related to Our Units, Partnership Structure and Ownership
Affiliates of ArcLight directly own our General Partner, which has sole responsibility for conducting our business and managing our operations. These affiliates elect all of the members of the Board. These affiliates and our General Partner have conflicts of interest with us and limited fiduciary duties, and they may favor their own interests to the detriment of us and our unitholders, including in connection with the Pending Merger.
Affiliates of ArcLight and our General Partner have the power to appoint all of the officers and directors of our General Partner. The directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner that is beneficial to it, and have no duty to us or our common unitholders. Conflicts of interest may arise, including in connection with the Pending Merger, between these affiliates and our General Partner, on the one hand, and us and our noteholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of these affiliates over our interests and the interests of our noteholders. In addition, these conflicts between the General Partner and its affiliates and the Partnership include the following situations, among others:

- neither the Partnership Agreement nor any other agreement requires these affiliates of ArcLight to pursue a business strategy that favors us, and the officers and directors of these affiliates may have a fiduciary duty to make these decisions in the best interests of these affiliates of ArcLight and their respective direct and indirect owners, respectively, which may be contrary to our interests. These affiliates of ArcLight may choose to shift the focus of their investment and growth to areas not served by our assets;
- these affiliates of ArcLight, their respective direct and indirect owners and their respective affiliates are not limited in their ability to compete with us and may offer business opportunities or sell midstream assets to third parties without first offering us the right to bid for them;
- our General Partner is allowed to take into account the interests of parties other than us in resolving conflicts of interest and exercising certain rights under our Partnership Agreement, which has the effect of limiting its duty to our unitholders;

- our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing its duties, limits our General Partner's liabilities, and also restricts the remedies available to our noteholders for actions that, without the limitations, might constitute breaches of such fiduciary duties;
- except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval;
- disputes may arise under our commercial agreements or acquisition agreements with these affiliates of ArcLight;

- our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of 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 capital expenditures and whether a capital 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 that is distributed to our unitholders and to our General Partner as well as the conversion of the Convertible Preferred Units into common units;
- our General Partner determines which costs incurred by it are reimbursable by us;
- 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 a distribution on the Convertible Preferred Units, to make incentive distributions or to accelerate the expiration of a subordination period;
- our Partnership Agreement permits us to classify up to $11.5 million as operating surplus, even if it is generated from asset sales, nonworking capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our Convertible Preferred Units or to our General Partner in respect of the General Partner interest or the incentive distribution rights;
- our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations;
- our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our General Partner controls the enforcement of the 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;
- our General Partner may transfer its IDRs without unitholder approval;
- 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 (the "Conflicts Committee") of the Board or our unitholders. This election may result in lower distributions to our common unitholders in certain situations; and
- although ArcLight has provided cash and other support for our liquidity in the past, it is under no obligation to do so in the future.

The affiliates of ArcLight that own our General Partner are not limited in their ability to compete with us and are not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.
The affiliates of ArcLight that own our General Partner are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, affiliates of our General Partner and the entities owned or controlled by affiliates of our General Partner, including these affiliates of ArcLight have acquired, constructed or disposed of, and may continue to acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. Moreover, while these affiliates of ArcLight may offer us the opportunity to buy additional assets from them, they are under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed. Although ArcLight has provided us with financial support in the past, it is no longer doing so and under no obligation to do so in the future. 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 New York Stock Exchange (“NYSE”) does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.
Our common units are listed on the NYSE. Because we are 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. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

If you are not an eligible holder, you may not receive distributions or allocations of income or loss on your common units and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If you are not an eligible holder, our General Partner may elect not to make distributions or allocate net income or loss on your units, and you run the risk of having your units redeemed by us at the lower of your purchase price for the units and the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Common units held by persons who are non-taxpaying assignees will be subject to the possibility of redemption.

Our Partnership Agreement gives our General Partner the power to amend the agreement to avoid any adverse effect on the maximum applicable rates chargeable to customers by us under FERC regulations or to reverse an adverse determination that has occurred regarding such maximum rate. If our General Partner determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us, then our General Partner may adopt such amendments to our Partnership Agreement as it determines are necessary or advisable to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our General Partner to obtain proof of the U.S. federal income tax status.

Our Partnership Agreement requires that we pay a distribution to holders of Series C Units in cash before we are permitted to make any distribution in respect of our common units for the quarter ending March 31, 2019 and each quarter thereafter.

Our Partnership Agreement requires us to pay a quarterly distribution to holders of Series A Units and Series C Units. Distributions paid to holders of Series C Units for the quarter ending March 31, 2019 and each quarter thereafter must be paid in cash. If we fail to pay the required distribution to holders of Series C Units in cash, our Partnership Agreement prohibits us from making a distribution on account of securities junior to or in parity with the Series C Units, including cash distribution on our common units and in-kind distributions to holders of Series A Units. Failure to timely pay a distribution required in respect of preferred units may result in the accrual of interest on such untimely payment of a distribution, as described in our Partnership Agreement. This accrual and arrearage on our preferred units may further delay or prevent payment of any distribution on our common units.

Our Partnership Agreement replaces our General Partner's duties to us with limited contractual duties and the holders of our common units and restricts the remedies available to holders of our common units for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that eliminate and replace the fiduciary duties to which our General Partner would otherwise be held by 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, as defined in our Partnership Agreement, our General Partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as such decisions are made in good faith, meaning that it believed that the decision was in, or not opposed to, the best interest of our partnership;
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal

matter, acted with knowledge that the conduct was criminal; and

- provides that our General Partner will not be in breach of its obligations under the Partnership Agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

a. approved by the Conflicts Committee, although our General Partner is not obligated to seek such approval;

b. approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates;

c. on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

33

d. fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If an affiliate transaction or the resolution of a conflict of interest is approved as described above, then it will be presumed that, in making its decision, the Conflicts Committee and Board 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.

Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The Board will be chosen by HPIP and AMID GP Holdings, LLC ("AMID GP Holdings"). Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. 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. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, it will be difficult to remove our General Partner without its consent.

Our unitholders will find it difficult to remove our General Partner without its consent because our General Partner and its affiliates own more than a majority of our units. The vote of the holders of at least 66 2/3% of all outstanding limited partner interests voting together as a single class is required to remove our General Partner. As of March 18, 2019, ArcLight indirectly held common units or convertible preferred units representing 51.0% of the voting power of our then-outstanding common and preferred units which vote together as a class. In addition, our Partnership Agreement contains other provisions that make removal of our General Partner without its consent difficult or costly, such as redemption of a non-consenting General Partner's interest.

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

Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board, cannot vote on any matter.

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 in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of HPIP or AMID GP Holdings to transfer all or a portion of their ownership 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 officers of our General Partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

We may issue additional units, including units that are senior to the common units and pari passu with our existing convertible preferred units, without your approval, which would dilute your existing ownership interests.

Our Partnership Agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities 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 of the convertible preferred 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.

In the event that the Pending Merger is not consummated, ArcLight may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.
As of March 18, 2019, ArcLight and its affiliates beneficially owned 51% of our outstanding common units on a fully converted basis, including all of our Series A Units and Series C Units and Series C Warrants. The Series A Units, Series C Units and Series C Warrants are convertible into common units at the election of ArcLight at any time. The sale of these units and the common units owned directly and indirectly by ArcLight and its affiliates could have an adverse impact on the price of the common units or on any trading market that may develop.
As our common units are designed to be yield-oriented securities, suspension of distributions and increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.
Until the second quarter 2018, we had paid at least the minimum quarterly distribution on our common units. Beginning with the second quarter of 2018, we reduced our quarterly distribution per common unit to 25% of the minimum quarterly distribution. For the fourth quarter of 2018, we did not pay any quarterly distribution on our common units and do not expect to pay a quarterly distribution on our common units for the first quarter of 2019. These reductions have had an adverse impact on the trading price of our common units. Similar future announcements may continue to reduce or maintain a lower trading price of our common units.

When we are paying distributions on our common units, as with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and 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 while we are making distributions, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

In the event that the Pending Merger is not consummated, our General Partner has a limited call right that may require you to sell your units at an undesirable time or price.
In the event that the Pending Merger is not consummated and our General Partner and its affiliates own more than 80% of our common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our Partnership Agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units.
Your 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. You could be liable for any and all of our obligations as if you were a General Partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your 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 that were wrongfully distributed to them.
Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you 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 an 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. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the Partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the Partnership are counted for purposes of determining whether a distribution is permitted.

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

Our assets include 35.7% non-operated interest in Delta House Class A Units, a 16.7% non-operated interest in Tri-States, a 25.3% non-operated interest in Wilprise, a non-operated interest in Mesquite and a 26.3% non-operated interest in Pinto, any of which may be deemed to be an "investment security" within the meaning of the Investment Company Act of 1940, as amended (the "Investment Company Act"). In the future, we may acquire additional minority owned interests that could be deemed "investment securities." If a sufficient amount of our assets are deemed to be "investment securities" within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage 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 or all of these events may have a material adverse effect on our business. Moreover, treatment of us as an investment company would prevent our qualification as a partnership for U.S. federal income tax purposes in which case we would be treated as a corporation for U.S. federal income tax purposes and be subject to U.S. federal income tax at the corporate tax rate, significantly reducing the cash available for distributions.

Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for U.S. federal income tax purposes or we become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to the unitholders would be substantially reduced.

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

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a publicly traded partnership such as ours to be treated as a corporation for U.S. federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, the IRS could disagree with the positions we take or a change in our business (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 U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 21%, and would likely pay state income tax at varying rates. Distributions to a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to the unitholder. 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 for U.S. federal income tax purposes 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.

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 federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.
The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of the U.S. Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. If successful, such proposals or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.
We believe the income that we treat as qualifying satisfies the requirements under these regulations. However, there are no assurances that recent regulations will not be revised to take a position that is contrary to our interpretation of current law.
Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay the State of Texas a margin tax that is assessed at 0.75% of taxable margin apportioned to Texas. Imposition of such a tax on us by any state will reduce the cash available for distribution to unitholders. The 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 federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.
Compliance with and changes in tax laws could adversely affect our performance.
We are subject to extensive tax laws and regulations, including federal and state income tax laws and transactional tax laws such as excise, sales/use, payroll, franchise and ad valorem tax laws. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Further, taxing authorities may change their application of existing taxes, so that additional entities or transactions may become subject to an existing tax. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional tax payments, as well as interest and penalties. The costs of these audits are borne indirectly by the unitholders and our General Partner because such costs reduce our cash available for distribution.
If the IRS contests the U.S. federal income tax positions we take, the market for our common units may be adversely impacted, and the cost of any IRS contest will reduce our cash available for distribution to the 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. The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS, and the outcome of any such contest, may increase a unitholder's tax liability and result in adjustment to items unrelated to us and could materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by the unitholders and our General Partner because such costs will reduce our cash available for distribution.
If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.
If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. Although our General Partner may elect to have our unitholders and former unitholders take such audit adjustments 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. If we are unable to have the unitholders take such audit adjustment into account in accordance with their interests during the taxable year under audit, the current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units during the taxable year under audit. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

The unitholders' share of our income will be taxable to them for U.S. federal income tax purposes even if the unitholders do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income, which could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of U.S. federal income taxes and, in some cases, state and local income taxes on its share of our taxable income even if it receives no cash distributions from us. The unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Certain actions that we may take, such as issuing additional units, may increase the U.S. federal income tax liability of unitholders.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder's share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder's units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder's tax basis in its units.

In addition, the U.S. federal income tax liability of a unitholder could be increased if we take advantage of debt reduction opportunities (e.g., debt exchanges, debt repurchases or modifications of existing debt), dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as (i) to repay indebtedness currently outstanding or (ii) to acquire property that is not eligible for depreciation or amortization for U.S. federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our existing assets.

Unitholders may be subject to limitations on their ability to deduct interest expense we incur.

Our ability to deduct business interest expense will be limited for U.S. federal income tax purposes to an amount equal to the sum of (i) our business interest income during the taxable year and (ii) 30% of our adjusted taxable income for such taxable year. For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. If we are not entitled to fully deduct our business interest in any taxable year, such excess business interest expense will be allocated to each unitholder as excess business interest and can be carried forward by the unitholder to successive taxable years and used to offset any excess taxable income allocated by us to such unitholder. Any excess business interest expense allocated to a unitholder will reduce such unitholder’s tax basis in its partnership interest in the year of the allocation even if the expense does not give rise to a deduction to the unitholder in that year. Immediately prior to a disposition of its shares, a unitholder’s tax basis will be increased by the amount by which such basis reduction exceeds the excess interest expense that has been deducted by such unitholder.

There are limits on the deductibility of losses that may adversely affect unitholders.

In the case of taxpayers subject to the passive loss rules (generally, individuals, closely-held corporations and regulated investment companies), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of the unitholder’s entire investment in us in a fully taxable transaction with an unrelated party. A unitholder’s share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships.

Further, in addition to the other limitations described above, non-corporate taxpayers may only deduct business losses up the gross income or gain attributable to such trade or business plus $250,000 ($500,000 for unitholders filing jointly). Amounts that may not be deducted in a taxable year may be carried forward into the following taxable year. This limitation shall be applied after the passive loss limitations and, unless amended, applies only to taxable years beginning prior to December 31, 2025.

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

If a unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions to a unitholder in excess of the total net taxable income allocated to the unitholder decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if the unitholder sells the common units at a price greater than the unitholder's tax basis in those common units, even if the price received by the unitholder is less than the original cost. Furthermore, a substantial portion of the amount realized on any sale of a unitholder's common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if the unitholder sells its common units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale. Further, net capital loss, if any, recognized by a unitholder may only offset unitholder's capital gains for the taxable year and, in the case of individuals, up to $3,000 of ordinary income per year.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts, or IRAs, other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our operating 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, which may be taxable to them. Further, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. persons are generally taxed and subject to U.S. federal income tax filing requirements 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 its interest will be subject to U.S. federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the non-U.S. unitholder.

The tax law also imposes a federal income tax withholding obligation of 10% of the amount realized upon a non-U.S. person's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the application of this withholding rule to dispositions of publicly traded partnership interests has been temporarily suspended by the IRS until regulations or other guidance that resolves the challenges have been issued. It is not clear if or when such regulations or guidance will be issued. Non-U.S. persons should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholders' tax returns.

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

We prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Treasury recently adopted final regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders to ours. These regulations apply to certain publicly-traded partnerships, including us, for taxable years beginning on or after August 3, 2015. However, these regulations do not specifically authorize the use of the proration method we have adopted. 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 the unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those 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 units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 units.

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

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

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

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not reside as a result of investing in our units.

In addition to U.S. federal income taxes, 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 do business or own property, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder's responsibility to file all U.S. federal, foreign, state, local and non-U.S. tax returns.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unit holder's income tax liability to the state, generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

A description of our properties is contained in Item 1. Business – Our Segments of this 2018 Form 10-K and is incorporated into this Item 2. by reference.

We lease our principal executive offices located at 2103 CityWest Blvd., Bldg. 4, Suite 800, Houston, Texas 77042. Our telephone number is 346-241-3400. We believe that our existing facilities are adequate to meet our needs for the immediate future and that additional facilities will be available on commercially reasonable terms as needed.

Item 3. Legal Proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate impact of any proceedings cannot be predicted with certainty, our management believes that the resolution of any of our pending proceedings will not have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

Our common units have been listed on the New York Stock Exchange ("NYSE") since July 27, 2011, under the symbol "AMID."

Unitholder Matters

As of March 18, 2019, there were 111 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. As of March 18, 2019, we have approximately 11,342,197 Series A Units, 9,514,330 Series C Units and 980,889 General Partner units.

Our Distribution Policy

Our Partnership Agreement requires us to distribute all of our available cash quarterly. Generally, our available cash is (a) the sum of our i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and ii) cash on hand resulting from working capital borrowings made after the end of the quarter, (b) less the amount of any cash reserves established to i) provide for the proper conduct of the business and ii) comply with applicable law or loan or other contractual agreement to which we are part, including our Credit Agreement. When we pay a quarterly cash dividend, we pay it to those unitholders of record on the applicable record date, as determined by the General Partner.

Our cash distribution policy, as expressed in our Partnership Agreement, may not be modified or repealed without amending our Partnership Agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business, the amount of reserves our General Partner establishes in accordance with our Partnership Agreement as described above and contractual agreements, such as our Credit Agreement, which may restrict our ability to declare or make a distribution from time to time. We may not be permitted to make distributions and may not have any available cash from time to time. We will pay any distributions on or about the 15th of each February, May, August and November to holders of record on or about the 5th of each such month. If the distribution date does not fall on a business day, we will make any distribution on the business day immediately preceding the indicated distribution date.

As a result of the Second Amendment, we are not permitted to declare or make any cash distributions to our unitholders until our consolidated total leverage ratio is reduced to less than 5.00:1.00, as shown in the compliance certificate required to be delivered together with audited consolidated financial statements for the most recently completed fiscal year and unaudited consolidated financial statements for the most recently completed quarter. Therefore, the Credit Agreement prohibited us from making any cash distributions on our common units and preferred units with respect to the fourth quarter of 2018, and we do not expect to make any cash distributions on our common units and preferred units with respect to the first quarter of 2019. Under our Partnership Agreement, we are required to make all distributions and any arrearages on all preferred units before making any distribution on common units.

The following table sets forth the number of units outstanding at December 31, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017
Series A convertible preferred units	11,010	10,719
Series C convertible preferred units	9,242	8,965
Limited partner common units	54,017	52,711
General Partner units	981	965

General Partner Units

Our General Partner's initial 2.0% interest in distributions has been reduced to 1.3% as of December 31, 2018 due to the issuance of additional units and the General Partner's failure to contribute a proportionate amount of capital to us to maintain its initial 2.0% General Partner notional interest in connection with such issuance.

Series A Units

Distributions on Series A Units can be made with paid-in-kind Series A Units, cash or a combination thereof, at the discretion of the Board, which began since the distribution for the three months ended June 30, 2014. At December 31, 2018, we accrued $4.0 million of contractual paid-in-kind distributions on the Series A Units. Our Partnership Agreement prohibits us from declaring or making any distributions in respect of the Series A Units if we fail to pay in full or part a required distribution on the Series C Units until such untimely payment is paid in full in accordance with our Partnership Agreement. As a result, we will accrue arrearages on the Series A Units with respect to any quarters for which we accrue arrearages on the Series C Units. For information concerning our ability to make distributions in respect of the Series C Units, see Series C Units below.

Series C Units

Distributions on Series C Units can be made with paid-in-kind Series C Units, cash or a combination thereof, at the discretion of the Board and upon the consent of the holders of the Series C Units for the quarters through and including the quarter ended December 31, 2018. At December 31, 2018, we accrued $3.5 million of contractual paid-in-kind distributions on the Series C Units.

With respect to quarters ending March 31, 2019 and all quarters thereafter, distributions on Series C Units must be made in cash. As a result of the Second Amendment, the Series C Units will accrue arrearages with respect to unpaid distributions starting with the quarter ending March 31, 2019. We do not plan to pay a cash distribution on the Series C Units with respect to the quarter ending March 31, 2019.

Securities Authorized for Issuance Under Equity Compensation Plans

Information on our equity compensation plans can be found in Part II. Item 8. Note 18. Incentive Compensation of this 2018 Form 10-K.

Item 6. Selected Financial Data

The following table presents selected historical consolidated financial and operating data for the periods and as of the dates indicated. We derived this information from our historical consolidated financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those consolidated financial statements and notes, which for the years 2018, 2017, and 2016 begin on page F-1 to this 2018 Form 10-K.

For a detailed discussion of the following table, see Item 7. MD&A of this 2018 Form 10-K (in thousands, except per unit and operating data).

42

	Years ended December 31,				
	2018 (1)	2017 (2)	2016 (4)	2015 (4)	2014 (4)
Statements of Operations Data:					
Revenue	$805,354	$651,435	$589,026	$750,304	$838,949
Operating expenses:					
Cost of sales	592,040	457,371	393,351	567,682	672,948
Direct operating expenses	87,677	82,256	71,544	71,729	58,048
Corporate expenses	89,706	112,058	89,438	65,327	60,465
Termination fee	17,000	—	—	—	—
Depreciation, amortization and accretion	87,171	103,448	90,882	81,335	57,818
(Gain) loss on sale of assets, net	(95,118)	(4,063)	688	2,860	4,087
Impairment of long-lived assets and intangible assets	1,610	116,609	697	—	21,344
Impairment of goodwill	—	77,961	2,654	148,488	—
Total operating expenses	780,086	945,640	649,254	937,421	874,710
Operating income (loss)	25,268	(294,205)	(60,228)	(187,117)	(35,761)
Other income (expense), net:					
Interest expense, net of capitalized interest	(82,410)	(66,465)	(21,433)	(20,077)	(16,497)
Other income (expense), net	560	36,254	254	1,460	(1,096)
Loss on extinguishment of debt	—	—	—	—	(1,634)
Earnings in unconsolidated affiliates	81,929	63,050	40,158	8,201	348
Income (loss) from continuing operations before income taxes	25,347	(261,366)	(41,249)	(197,533)	(54,640)
Income tax expense	(32,995)	(1,235)	(2,580)	(1,885)	(856)
Loss from continuing operations	(7,648)	(262,601)	(43,829)	(199,418)	(55,496)
Discontinued operations(3):					
Income (loss) from discontinued operations, including gain on sale	—	44,095	(4,715)	(423)	(24,071)
Net loss	(7,648)	(218,506)	(48,544)	(199,841)	(79,567)
Net (income) loss attributable to noncontrolling interests	(116)	(4,473)	(2,766)	13	(3,993)
Net loss attributable to the Partnership	$(7,764)	$(222,979)	$(51,310)	$(199,828)	$(83,560)
General Partner's interest in net loss	$(101)	$(2,981)	$(233)	$(1,823)	$(398)
Limited Partners' interest in net loss	$(7,663)	$(219,998)	$(51,077)	$(198,005)	$(83,162)
Limited Partners' net loss per common unit:					
Basic and diluted:					
Loss from continuing operations	$(0.75)	$(5.70)	$(1.51)	$(4.91)	$(2.77)
Income (loss) from discontinued operations, including gain on sale	—	0.85	(0.09)	(0.01)	(0.52)
Net loss per common unit	$(0.75)	$(4.85)	$(1.60)	$(4.92)	$(3.29)
Weighted average number of common units outstanding:					
Basic and diluted	53,136	52,043	51,176	45,050	27,524

Other Financial Data:					
Adjusted EBITDA[5]	$184,614	$176,394	$177,565	$100,721	$ 74,286
Total segment gross margin[6]	285,480	244,854	226,213	179,856	153,524
Distribution declared per common unit	$0.62	$1.65	$1.99	$2.14	$ 1.85
Balance Sheet Data (at period end):					
Cash and cash equivalents	$9,069	$8,782	$5,666	$1,987	$ 3,824
Restricted cash	35,951	25,397	323,564	5,037	11,511
Accounts receivable, net	76,632	98,132	67,625	61,016	116,676
Property, plant and equipment, net	997,708	1,095,585	1,066,608	981,321	887,045
Total assets	1,687,696	1,923,466	2,349,321	1,751,889	1,865,210
Current portion of long-term debt	522,966	7,551	5,438	2,758	3,141
Long-term debt	500,739	1,201,456	1,235,538	687,100	456,965

The following transactions affect comparability between years:

(1) In July 2018, we completed the sale of Marine Products and in December 2018, we completed the sale of Refined Products.

(2) i) In June 2017, we acquired a 100% interest in VKGS which was accounted for as a business combination and was included in our Offshore Pipelines and Services segment; ii) in August 2017, we acquired a 100% interest in POGS; the outstanding interests in one of our equity investments, MPOG, which was accounted for as a change in control and has been consolidated from the acquisition date; and the remaining equity interest in our consolidated subsidiary, AmPan, each of which were included in our Offshore Pipelines and Services segment; iii) in September 2017, we acquired an additional 15.5% equity interest in Delta House Class A units, which we accounted for as an equity method investment and was included in our Offshore Pipelines and Services segment; iv) in October 2017, we acquired an additional 17.0% membership interest in Destin which we accounted for as an equity method investment and was included in our Liquid Pipelines and Services segment and v) in November 2017, we acquired 100% of the equity interest in Trans-Union which represented an asset acquisition among entities under common control and was included in our Natural Gas Transportation Services segment.

(3) On September 1, 2017, the Partnership completed the disposition of its Propane Business and has classified the results of operations as discontinued operations for all periods.

(4) i) In October 2016 and April 2016, we acquired 6.2% and a 1% non-operated interests in Delta House Class A units, which we accounted for as equity method investments and were included in our Offshore Pipelines and Services segment; ii) in April 2016, we acquired membership interests in Destin (49.7%), Tri-States (16.7%), Okeanos (66.7%), and Wilprise (25.3%), which we accounted for as equity method investments and were included in our Liquid Pipelines and Services and Offshore Pipelines and Services segments; iii) in April 2016 we acquired a 60% interest in AmPan which we consolidated for financial reporting purposes and was included in our Offshore Pipelines and Services segment; iv) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House Class A units, which we accounted for as an equity method investment and was included in our Offshore Pipelines and Services segment; v) in February 2016, we completed the sale of our crude oil supply and logistics operations which was included in our Liquid Pipelines and Services segment; vi) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which were reported in our Gas Gathering and Processing Services segment; vii) in December 2013, we acquired Blackwater, which was reported in our Terminalling Services segment; and viii) in April 2013, we acquired the High Point System, which was included in our Natural Gas Transportation Services segment.

(5) For a definition of Adjusted EBITDA and Total segment gross margin and a reconciliation to their most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use these metrics to evaluate our operating performance, see Item 7. MD&A – How We Evaluate Our Operations of this

2018 Form 10-K.

(6) Total segment gross margin for years ended December 31, 2015 and 2014 have not been recast to reflect the reorganization of our segments as discussed in Part I. Item 1. Business of this 2018 Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the audited consolidated financial statements and the related notes thereto included elsewhere in this 2018 Form 10-K. This discussion contains forward-looking statements that reflect management's current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption "Cautionary Statement About Forward-Looking Statements."

Overview

Please read Part I. Item 1. Business of this 2018 Form 10-K for a description of our assets, operations and segments, including the changes in our segments, as of December 31, 2018.

Financial Highlights

Financial highlights during the year ended December 31, 2018, include the following:

- Net loss attributable to the Partnership was $7.8 million for the year ended December 31, 2018, compared to $223.0 million for the prior year, a decrease of 97% compared to the prior year.
- Adjusted EBITDA was $184.6 million for the year ended December 31, 2018, an increase of 5% compared to the prior year.
- Distributable cash flow ("DCF") was $69.8 million for the year ended December 31, 2018, compared to $91.1 million for the prior year, a decrease of 24% compared to the prior year.
- Total segment gross margin was $285.5 million for the year ended December 31, 2018, an increase of 17% compared to the prior year.
- We distributed $54.5 million to our Limited Partners during the year ended December 31, 2018, which represents our distribution for the fourth quarter of 2017 and the first three quarters of 2018.

Adjusted EBITDA, DCF and Total segment gross margin are each non-GAAP measures. The GAAP measure most comparable to Adjusted EBITDA, DCF and Total segment gross margin is Net income (loss) attributable to the Partnership. Please see "Non-GAAP Financial Measures" for a definition and reconciliation to the most comparable GAAP measure.

On October 31, 2017, we, our General Partner, our wholly owned subsidiary, Cherokee Merger Sub LLC, Southcross Energy Partners, L.P. (“SXE”) and Southcross Energy Partners GP, LLC, entered into an Agreement and Plan of Merger (the “SXE Merger Agreement”), and we, our General Partner and Southcross Holdings LP (“Holdings LP”) entered in to a Contribution Agreement (“Contribution Agreement”). The SXE Merger Agreement and the Contribution Agreement originally provided for an outside closing date of June 1, 2018. On June 1, 2018, the parties to the SXE Merger Agreement and the Contribution Agreement agreed to extend such outside closing date to June 15, 2018 (the “Outside Closing Date”).

On July 29, 2018, following the expiration of the Outside Closing Date, we received notice of termination of the SXE Merger Agreement from SXE and notice of termination of the Contribution Agreement from Holdings LP. Pursuant to the terms of the Contribution Agreement, we were required to pay Holdings LP a $17 million termination fee. The termination fee was paid in August 2018 and is presented as Termination fee in the Consolidated Statement of Operations.

On July 27, 2018, we announced a revised capital allocation strategy that was intended to reduce leverage and provide additional capital for strategic growth. We determined to retain operating cash flow through a reduction in the amount of our quarterly distribution on our common units, and to pursue increased non-core asset sales and use the proceeds from both to reduce leverage.

Amendment to Credit Agreement

During 2018, we amended the Original Credit Agreement by entering into the First Amendment to the Second Amended and Restated Credit Agreement on June 29, 2018 (the "First Amendment") and by entering into the Second Amendment to the Second Amended and Restated Credit Agreement on December 27, 2018 (the "Second

Amendment", and collectively, the “Amendments” and, the Original Credit Agreement as amended by the Amendments, the “Credit Agreement”) with a syndicate of lenders and Bank of America, N.A., as administrative agent.

The Amendments, among other things, amend certain financial covenants and create certain obligations for repayment of borrowings and related reduction of commitments. Under the Amendments, the Partnership is not permitted to declare or make any cash distributions until its Consolidated Total Leverage Ratio is reduced to less than 5.00:1.00, as shown in the Compliance Certificate required to be delivered together with audited consolidated financial statements for the most recently completed fiscal year and unaudited consolidated financial statements for the most recently completed quarter.

We entered into a Letter Agreement (the “Waiver”), effective as of March 26, 2019, with a syndicate of lenders and Bank of America, N.A., as administrative agent, to waive certain covenants contained in the Credit Agreement that (i) require us to provide audited financial statements that are not subject to any “going concern” or like qualification or exception or any qualification or exception as to the scope of such audit and (ii) limit our ability to report the existence of a material weakness in the Partnership's internal control over financial reporting (the "Financial Statements Audit Requirement"). Additionally, the Waiver extends the deadline under the Credit Agreement by which we are required to deliver to the administrative agent certain financial statements (the "Financial Statements Delivery Deadline"). Under the terms and conditions set forth in the Waiver, certain lenders (as required in our Credit Agreement) agreed to extend the Financial Statements Delivery Deadline to April 30, 2019.

As previously disclosed, the Partnership's Credit Agreement matures on September 5, 2019 and has not been renewed. Until such time as the Partnership has executed an agreement to refinance or extend the maturity of the Credit Agreement, the Partnership cannot conclude that it is probable that it will do so, and accordingly, this raises substantial doubt about the Partnership's ability to continue as a going concern. For more information regarding the Partnership's going concern qualification, see Part II. Item 8. Note 14. Debt Obligations of our 2018 Form 10-K.

As the renewal or refinance of the Credit Agreement remains uncertain, the audited financial statements contained in this Form 10-K include a note regarding our ability to continue as a going concern. Prior to our entry into the Waiver, the existence of this going concern qualification in our audited financial statements would have constituted an event of default under the Credit Agreement. Pursuant to the Waiver, the administrative agent and certain lenders (as required by the Credit Agreement) have waived the Financial Statements Audit Requirement for the fiscal year ended December 31, 2018. Although we entered into the Waiver to address the event of default otherwise arising pursuant to the existence of a going concern note and material weakness exception in our audited financial statements contained in this Form 10- K, there is no guarantee that our lenders will agree to waive events of default or potential events of default in the future. Additionally, the existence of a material weakness in the Partnership's internal control over financial reporting may constitute an event of default under the Credit Agreement.

Going Concern Assessment and Management's Plans

Pursuant to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") No. 205-40, Presentation of Financial Statement – Going Concern (Subtopic 205-40): Disclosure of Uncertainties About an Entity's Ability to Continue as a Going Concern, we are required to assess our ability to continue as a going concern for a period of one year from the date of the issuance of these consolidated financial statements. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year from the financial statement issuance date. Our Credit Agreement matures on September 5, 2019 and has not been renewed as of the date of the issuance of these consolidated financial statements.

As discussed in Item 8. Note 21. Related Party Transactions, of this 2018 Form 10-K, on September 27, 2018, the Board received a non-binding proposal from Magnolia, an affiliate of ArcLight to acquire the common units that it does not already own. On March 17, 2019, we entered into the Merger Agreement and expect the Pending Merger to close in the second quarter of 2019. As a result of this ongoing process, management has deferred finalization of a renewal of the Credit Agreement. As the Merger Agreement is subject to customary closing conditions and because the Pending Merger may affect how, or if, the Partnership elects to obtain a maturity extension, management has purposefully delayed maturity extensions and other balance sheet modifications due to unreasonable costs and burdens to the Partnership.

While the Partnership intends to renew or extend the terms of its Credit Agreement, until such time as we have executed an agreement to refinance or extend the maturity of our Credit Agreement, we cannot conclude that it is probable we will do so, and accordingly, this raises substantial doubt about our ability to continue as a going concern. The accompanying financial statements have been prepared assuming we will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The accompanying financial statements do not include adjustments that might result from the outcome of the uncertainty, including any adjustments to reflect the possible future effects of the recoverability and classification of recorded asset amounts or other amounts and classifications of liabilities that might be necessary should we be unable to continue as a going concern.

As the renewal or refinance of the Credit Agreement remains uncertain, the audited financial statements contained in this Form 10-K include a note regarding our ability to continue as a going concern. Prior to our entry into the Waiver, the existence of this going concern qualification in our audited financial statements would have constituted an event of default under the Credit Agreement. Pursuant to the Waiver, the administrative agent and certain lenders (as required by the Credit Agreement) have waived the Financial Statements Audit Requirement for the fiscal year ended December 31, 2018. Although we entered into the Waiver to address the event of default otherwise arising pursuant to the existence of a going concern and material weakness note in our audited financial statements contained in this Form 10-K, there is no guarantee that our lenders will agree to waive events of default or potential events of default in the future.

How We Evaluate Our Operations

To supplement our financial information presented in accordance with GAAP, our management uses additional measures known as "non-GAAP financial measures," to evaluate past performance and prospects for the future. Management views these metrics as important factors in evaluating our profitability and reviews these measurements at least monthly for consistency and trend analysis. These metrics include throughput, Total segment gross margin, Operating margin and Direct operating expenses on a segment basis, and Adjusted EBITDA and DCF on a company-wide basis.

Throughput

In our Gas Gathering and Processing Services segment, we must continually obtain new supplies of natural gas, NGLs and condensate to maintain or increase throughput on our systems. Our ability to maintain or increase existing volumes of natural gas, NGLs and condensate is impacted by i) the level of work-overs or recompletions of existing connected wells and successful drilling activity of our significant producers in areas currently dedicated to or near our gathering systems, ii) our ability to compete for volumes from successful new wells in the areas in which we operate, iii) our ability to obtain natural gas, NGLs and condensate that has been released from other commitments and iv) the volume of natural gas, NGLs and condensate that we purchase from connected systems. We actively monitor producer activity in the areas served by our gathering and processing systems to maintain current throughput and pursue new supply opportunities.

In our Liquid Pipelines and Services segment, the amount of revenue we generate from our crude oil pipelines business depends primarily on throughput. We generate a portion of our crude oil pipeline revenues through long-term contracts containing acreage dedications or minimum volume commitments. Throughput on our pipeline system are affected primarily by the supply of crude oil in the market served by our assets. The revenue generated from our crude oil supply and logistics business depends on the volume of crude oil we purchase from producers, aggregators and traders and then sell to producers, traders and refiners as well as the volumes of crude oil that we gather and transport. Accordingly, we actively monitor producer activity in the areas served by our crude oil supply and logistics business and other producing areas in the United States to compete for volumes from crude oil producers. Revenues in this business are also impacted by changes in the market price of commodities that we pass through to our customers. The volume of crude oil stored at our crude oil storage facility in Cushing, Oklahoma has no impact on the revenue generated by our crude oil storage business because we receive a fixed monthly fee per barrel of shell capacity contracted that is not contingent on the usage of our storage tanks.

In our Natural Gas Transportation Services and Offshore Pipelines and Services segments, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput on our interstate and intrastate pipelines. Substantially all of the segment gross margin is generated under contracts with shippers, including producers, industrial companies, LDCs and marketers. We routinely monitor natural gas market activities in the areas served by our transmission systems to maintain current throughput and pursue new shipper opportunities.

In our Terminalling Services segment, we generally received fee-based compensation on guaranteed firm storage contracts, throughput fees charged to our customers when their products were either received or disbursed, and other operational charges associated with ancillary services provided to our customers, such as excess throughput, steam heating and truck weighing at our marine terminals. The amount of revenue we generated from our refined products terminals depended primarily on the volume of refined products that we handled. These volumes were affected primarily by the supply of and demand for refined products in the markets served directly or indirectly by our refined products terminals. Our refined products had butane blending capabilities.

Non-GAAP Financial Measures

Total segment gross margin, operating margin, Adjusted EBITDA and DCF are performance measures that are non-GAAP financial measures. Each has important limitations as an analytical tool because they exclude some, but not all, items that affect the most directly comparable GAAP financial measures. Management compensates for the limitations of these non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

You should not consider Total segment gross margin, Operating margin, Adjusted EBITDA or DCF in isolation or as a substitute for, or more meaningful than analysis of, our results as reported under GAAP. Total segment gross margin, Operating margin, Adjusted EBITDA and DCF may be defined differently by other companies in our industry. Our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure used by our management and external users of our consolidated financial statements, such as investors, commercial banks, research analysts and others, to assess: the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash flow to make cash distributions to our unitholders and our General Partner; our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

We define Adjusted EBITDA as net income (loss) attributable to the Partnership, plus depreciation, amortization and accretion expense, excluding noncontrolling interest share of depreciation, amortization and accretion, interest expense, net of capitalized interest excluding amortization of deferred financing costs, debt issuance costs paid during the period, unrealized gains (losses) on commodity derivatives, non-cash charges such as non-cash equity compensation expense and charges that are unusual such as transaction expenses primarily associated with our acquisitions, income tax expense, distributions from unconsolidated affiliates and General Partner’s contribution, less earnings in unconsolidated affiliates, discontinued operations, gains (losses) that are unusual, such as gain on revaluation of equity interest and gain (loss) on sale of assets, net and other non-recurring items that impact our business, such as construction and operating management agreement income (“COMA”) and other post-employment benefits plan net periodic benefit.

The GAAP measure most directly comparable to our performance measure Adjusted EBITDA is Net income (loss) attributable to the Partnership.

Distributable Cash Flow

DCF is a significant performance metric used by our management and by external users of our consolidated financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our consolidated financial statements can compute the coverage ratio of estimated cash flows to planned cash distributions. DCF is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure may indicate to investors whether we are generating cash flow at a level that can sustain our quarterly distribution rates. DCF is also a quantitative standard used throughout the investment community with respect to publicly traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder). DCF will not reflect changes in working capital balances.

We define DCF as Adjusted EBITDA less interest expense net of capitalized interest excluding unrealized gain (loss) on interest rate swaps and letter of credit fees, maintenance capital expenditures and distributions related to the Series A and Series C convertible preferred units. The GAAP financial measure most comparable to DCF is Net income (loss) attributable to the Partnership.

Total Segment Gross Margin and Operating Margin

Total segment gross margin and Operating margin are non-GAAP supplemental measures that we use to evaluate our performance.

For segments other than Terminalling Services, we define segment gross margin as total revenue plus unconsolidated affiliate earnings less unrealized gains (losses) on commodity derivatives, construction and operating management agreement income and the cost of sales. Gross margin for Terminalling Services also deducted direct operating expense which includes direct labor, general materials and supplies, and direct overhead. We define Total segment gross margin as the sum of the segment gross margins for each of our segments. We define Operating margin as Total segment gross margin less other direct operating expenses. The GAAP measure most directly comparable to Total segment gross margin and Operating margin is Net income (loss) attributable to the Partnership. For a reconciliation of Total segment gross margin and Operating margin to Net income (loss) attributable to the Partnership, see Note About Non-GAAP Financial Measures below.

Total segment gross margin is useful to investors and the Partnership's management in understanding our operating performance because it measures the operating results of our segments before certain non-cash items, such as depreciation and amortization, and certain expenses that are generally not controllable by our business segment development managers (who are responsible for revenue generation at the segment level), such as certain operating costs, general and administrative expenses, interest expense and income taxes. Operating margin is useful to investors and the Partnership's management for similar reasons except that operating margin includes all direct operating expenses, which allows the Partnership's management to assess the performance of our consolidated operating managers (who are responsible for cost management at the segment level). In addition, because these operating measures exclude interest expense and income taxes, they are useful for investors because they remove potential distortions between periods caused by factors such as financing and capital structures and changes in tax laws and positions.

Reconciliations

The following tables reconcile the non-GAAP financial measures of Total segment gross margin, Operating margin, Adjusted EBITDA and DCF to their nearest GAAP measure, Net income (loss) attributable to the Partnership, for the years ended December 31, 2018, 2017, and 2016 (in thousands):

	Years Ended December 31,		
	2018 [(1)]	2017 [(2)]	2016 [(3)]
Reconciliation of Total Segment Gross Margin and Operating Margin to Net loss attributable to the Partnership			
Gas Gathering and Processing Services	$51,888	$48,053	$50,040
Liquid Pipelines and Services	40,542	39,870	44,161
Natural Gas Transportation Services	36,130	23,005	18,616
Offshore Pipelines and Services	134,106	103,970	82,346
Terminalling Services	22,814	29,956	31,050
Total segment gross margin	285,480	244,854	226,213
Direct operating expenses [(4)]	(78,012)	(70,385)	(63,339)
Operating margin	207,468	174,469	162,874
Gains (losses) on commodity derivatives, net	2,036	(119)	(1,617)
Corporate expenses	(89,706)	(112,058)	(89,438)
Termination fee	(17,000)	—	—
Depreciation, amortization and accretion	(87,171)	(103,448)	(90,882)
Gain (loss) on sale of assets, net	95,118	4,063	(688)
Impairment of long-lived assets and intangible assets	(1,610)	(116,609)	(697)
Impairment of goodwill	—	(77,961)	(2,654)
Interest expense, net of capitalized interest	(82,410)	(66,465)	(21,433)
Other income, net	560	36,254	254
Other, net [(5)]	(1,938)	508	3,032
Income tax expense	(32,995)	(1,235)	(2,580)
Income (loss) from discontinued operations, including gain on sale	—	44,095	(4,715)
Net income attributable to noncontrolling interest	(116)	(4,473)	(2,766)
Net loss attributable to the Partnership	$(7,764)	$(222,979)	$(51,310)

During these years, we had the following transactions that affect comparability:

(1) Our Terminalling Services segment included Marine Products, which was divested in July 2018, and Refined Products, which was divested in December 2018.

(2) i) In June 2017, we acquired a 100% interest in VKGS which is accounted for as a business combination and is included in our Offshore Pipelines and Services segment; ii) in August 2017, we acquired a 100% interest in POGS, the outstanding interests in one of our equity investments MPOG, which is accounted for as a change in control and has been consolidated from the acquisition date; and the remaining equity interest in our consolidated subsidiary, AmPan, each of which are included in our Offshore Pipelines and Services segment; iii) in September 2017, we acquired an additional 15.5% equity interest in Delta House Class A units, which we account for as an equity method investment and is included in our Offshore Pipelines and Services segment; iv) in October 2017, we acquired an additional 17.0% membership interest in Destin which we account for as an equity method investment and is included in our Liquid Pipelines and Services segment and v) in November 2017, we acquired 100% of the equity interest in Trans-Union which represents an asset acquisition among entities under common control and is

included in our Natural Gas Transportation Services segment.

(3) i) In October 2016 and April 2016, we acquired 6.2% and 1% non-operated interests in Delta House Class A units which we account for as equity method investments and are included in our Offshore Pipelines and Services segment; ii) in April 2016, we acquired membership interests in Destin (66.7%), Tri-States (16.7%), Okeanos (66.7%), and Wilprise (25.3%), which we account for as equity method investments and are included in our Liquid Pipelines and Services and Offshore Pipelines and Services segments; and iii) in April 2016 we acquired a

60% interest in American Panther which we consolidate for financial reporting purposes and is included in our Offshore Pipelines and Services segment.

(4) Direct operating expenses exclude amounts related to the Terminalling Services segment as those costs are included in segment gross margin for the Terminalling Services segment. Direct operating expenses by segment includes (in thousands):

	Years ended December 31,		
	2018	2017	2016
Gas Gathering and Processing Services	$28,000	$34,040	$35,276
Liquid Pipelines and Services	11,162	13,061	11,195
Natural Gas Transportation Services	8,272	6,244	5,923
Offshore Pipelines and Services	30,578	17,040	10,945
Total direct operating expenses	$78,012	$70,385	$63,339

(5) Other, net includes realized (gain) loss on commodity derivatives and COMA loss (income).

	Years Ended December 31,		
	2018	2017	2016
Reconciliation of Net loss attributable to the Partnership to Adjusted EBITDA and DCF:			
Net loss attributable to the Partnership	$(7,764)	$(222,979)	$(51,310)
Depreciation, amortization and accretion[1]	87,171	102,766	90,112
Interest expense, net of capitalized interest	82,410	66,465	21,433
Amortization of deferred financing costs	(7,485)	(5,117)	(3,236)
Gain on extinguishment of debt	—	(1,870)	—
Debt issuance costs paid	6,977	5,705	5,328
Unrealized loss (gain) on commodity derivatives, net	2	—	48
Non-cash equity compensation expense	4,641	8,032	5,658
Corporate office relocation	—	—	9,096
Transaction expenses	28,791	42,860	14,084
Termination fee	17,000	—	—
Income tax expense	32,995	1,235	2,580
Impairment of long-lived assets and intangible assets	1,610	116,609	697
Impairment of goodwill	—	77,961	2,654
Discontinued operations [2]	—	(37,212)	30,058
Distributions from unconsolidated affiliates	97,713	90,846	83,046
General Partner contribution	17,732	34,614	7,500
Earnings in unconsolidated affiliates	(81,929)	(63,050)	(40,158)
COMA	(100)	(389)	(696)
Other post-employment benefits plan net periodic benefit	(32)	(20)	(17)
(Gain) loss on sale of assets, net	(95,118)	(4,063)	688
Gain on revaluation of equity interest	—	(35,999)	—
Adjusted EBITDA	$184,614	$176,394	$177,565
Interest expense, net of capitalized interest	(82,410)	(66,465)	(21,433)
Amortization of deferred financing costs	7,485	5,117	3,236
Unrealized (loss) gain on interest rate swaps	1,154	(1,109)	(10,375)
Gain on extinguishment of debt	—	1,870	—
Letter of credit fees	21	517	—
Maintenance capital	(15,970)	(8,892)	(6,751)
Preferred unit distributions	(25,061)	(16,311)	(15,142)
Distributable cash flow	$69,833	$91,121	$127,100

---

(1) Excludes Noncontrolling interest share of depreciation, amortization and accretion expense of $0.7 million and $0.7 million for the years ended December 31, 2017 and 2016, respectively.

(2) Represents aggregate adjustments related to our Propane Business for i) depreciation, amortization and accretion, (ii) unrealized (gain) loss on derivatives, (iii) (gain) loss on asset sales, (iv) goodwill impairment, (v) transaction expenses and (vi) the gain on sale.

General Trends and Outlook

We expect our business to continue to be affected by the Pending Merger and matters discussed above and the trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. Following the completion of the Pending Merger, our strategy and outlook may change materially. To the extent our underlying assumptions prove to be incorrect, our actual results may vary materially from our expected results.

Gas Gathering and Processing Services Segment. Except for our fee-based contracts, which may be impacted by throughput, the profitability of our Gas Gathering and Processing Services segment is dependent upon commodity prices, natural gas supply, and demand for natural gas, NGLs and condensate.

Liquid Pipelines and Services Segment. The profitability of our Liquid Pipelines and Services segment is dependent upon the price of crude oil. Throughput could decline should crude oil prices remain low resulting in decreased production in our areas of operation.

Natural Gas Transportation Services and Offshore Pipelines and Services Segments. Profitability of our Natural Gas Transportation Services and Offshore Pipelines and Services segments are dependent upon the demand to transport natural gas pursuant under our firm and interruptible transportation contracts. Throughput could decline should natural gas prices and drilling levels decline.

Capital Expenditures. We anticipate maintenance capital expenditures between $16.6 million and $20.3 million, and approved expenditures for expansion capital between $32.3 million and $39.5 million, for the year ending December 31, 2019. Forecast growth capital expenditures include pipeline and compression additions associated with the continued development of the Lavaca system, pipeline and truck stations on the Silver Dollar system and the installation of interconnects and compression on our Natural Gas Transportation Services assets to increase capacity.

Commodity Prices. Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $76.41 per barrel to a low of $42.53 per barrel from January 1, 2018 through March 18, 2019. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.24 per MMBtu to a low of $2.49 per MMBtu from January 1, 2017 through March 18, 2019. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices decline, this could lead to reduced profitability and may impact our liquidity, compliance with financial covenants in our revolving credit facility, and our ability to maintain our current distribution levels. Our long-term view is that as economic conditions improve and regulation burden is reduced, which has been the case under the current administration, commodity prices should reach levels that will support continued natural gas and crude oil production in the United States. Reduced profitability, if any, may result in future potential non-cash impairments of long-lived assets, goodwill or intangible assets.

Capital Markets. We have experienced limited ability to access the capital markets and this limitation may continue in the future. Volatility in the capital markets may impact our operations in multiple ways, including limiting our producers' ability to finance their drilling and workover programs and limiting our ability to fund drop downs, organic growth projects and acquisitions.

Results of Operations – Consolidated
Year ended December 31, 2018, compared to year ended December 31, 2017 (in thousands, except percentages)

	Years Ended December 31,			
	2018	2017	Change	%
Revenue	$805,354	$651,435	$153,919	24 %
Operating expenses:				
Cost of sales	592,040	457,371	134,669	29 %
Direct operating expenses	87,677	82,256	5,421	7 %
Corporate expenses	89,706	112,058	(22,352)	(20)%
Termination fee	17,000	—	17,000	*
Depreciation, amortization and accretion	87,171	103,448	(16,277)	(16)%
(Gain) loss on sale of assets, net	(95,118)	(4,063)	(91,055)	*
Impairment of long-lived assets and intangible assets	1,610	116,609	(114,999)	(99)%
Impairment of goodwill	—	77,961	(77,961)	(100)%
Total operating expenses	780,086	945,640	(165,554)	(18)%
Operating income (loss)	25,268	(294,205)	319,473	109 %
Other income (expense), net:				
Interest expense, net of capitalized interest	(82,410)	(66,465)	(15,945)	24 %
Other income, net	560	36,254	(35,694)	*
Earnings in unconsolidated affiliates	81,929	63,050	18,879	30 %
Income (loss) from continuing operations before income taxes	25,347	(261,366)	286,713	110 %
Income tax expense	(32,995)	(1,235)	(31,760)	*
Loss from continuing operations	(7,648)	(262,601)	254,953	(97)%
Income from discontinued operations, including gain on sale	—	44,095	(44,095)	*
Net loss	(7,648)	(218,506)	210,858	(96)%
Net income attributable to noncontrolling interests	(116)	(4,473)	4,357	97 %
Net loss attributable to the Partnership	$(7,764)	$(222,979)	$215,215	(97)%
Non-GAAP Financial Measures				
Total Segment gross margin (1)	$285,480	$244,854	$40,626	17 %
Adjusted EBITDA (2)	$184,614	$176,394	$8,220	5 %

* Not a meaningful percentage
(1) For reconciliation of Total Segment gross margin to its nearest GAAP measure, Income from continuing operations before income taxes, see the table in Non-GAAP Financial Measures.
(2) See the table in Non-GAAP Financial Measures for a reconciliation of Adjusted EBITDA to its nearest GAAP measure.

Net loss attributable to the Partnership for the year ended December 31, 2018 was $7.8 million, a decrease of $215.2 million, or 97% from December 31, 2017, primarily due to:

- increased revenues from both commodity sales and services, partially offset by higher cost of sales associated with higher revenues and increased operating expenses;
- benefit of $115.0 million from reduced long-lived assets and intangible assets impairment charges during the current year;
- benefit of $78.0 million from goodwill impairment charges taken in the prior year; and
-

the net gain of $95.1 million primarily from the sale of Marine Products and Refined Products during 2018 offset by a $29.8 million increase in income tax expense related to the gain from the sale of Marine Products.

The above items, which decreased the Net loss attributable to the Partnership between periods, were partially offset by:

- a $17.0 million termination fee from the termination of the SXE Merger Agreement in 2018;
- a $35.7 million reduction in other income primarily due to the fair value adjustment recorded in 2017 from the acquisition of the remaining interests of MPOG; and
- a $44.1 million reduction in income from discontinued operations, including gain on sale, which related to our Propane Business that was sold in the third quarter of 2017.

Total Segment gross margin for the year ended December 31, 2018 was $285.5 million, an increase of $40.6 million, or 17%, compared to the year ended December 31, 2017. The increase was primarily due to higher segment gross margin in our Gas Gathering and Processing Services, Natural Gas Transportation Services and Offshore Pipelines and Services segments offset by declines in our Terminalling Services segment.

Adjusted EBITDA for the year ended December 31, 2018 was $184.6 million, an increase of $8.2 million, or 5%, compared to the year ended December 31, 2017. The increase in Adjusted EBITDA was primarily due to improvements in Net Income attributable to the Partnership as discussed above.

We distributed $54.5 million to our Limited Partners during the year ended December 31, 2018 which represents the distribution for the fourth quarter of 2017 and the first three quarters of 2018.

Please see Results of Operations – Segment Results for a discussion of revenues, cost of sales, direct operating expenses and earning in unconsolidated affiliates.

Corporate expenses. Corporate expenses for the year ended December 31, 2018 were $89.7 million, a decrease of $22.4 million, or 20%, compared to the year ended December 31, 2017. This decrease was primarily due to lower transaction related costs associated with the Destin-Okeanos integration and JPE merger for $10.8 million, increased capitalized labor allocation of $3.9 million, reduced legal and regulatory compliance fees of $2.8 million, reduced office expenses of $1.4 million, reduced travel expenses of $1.2 million, reduced audit and tax fees of $1.0 million, reduced Environmental & Safety costs of $0.7 million and reduced IT Costs of $0.5 million.

Termination fee. The termination fee for the year ended December 31, 2018 was $17.0 million due to the termination of the SXE Merger Agreement.

Depreciation, amortization and accretion. Depreciation, amortization and accretion for the year ended December 31, 2018 was $87.2 million, a decrease of $16.3 million, or 16%, compared to the year ended December 31, 2017, primarily due to the acceleration of the accumulated amortization of a JPE customer relationship carried out in the beginning of the first quarter of 2017 through August 2017 of $10.0 million. The remaining difference is primarily due to Marine Products and Refined Products being classified as assets held for sale and subsequently sold in 2018, reduced depreciation and amortization due to the 2017 year-end impairments and decreased depreciation due to assets reaching the end of their depreciable lives in 2018.

Impairment of long-lived assets and intangible assets. Impairment of long-lived assets and intangible assets expense for the year ended December 31, 2018 was $1.6 million, a decrease of $115.0 million, compared to the year ended December 31, 2017. During the fourth quarter of 2018, we determined assets within our Liquid Pipelines Services segment and Offshore Pipelines and Services segment were impaired and recorded a $1.6 million impairment, compared to impairment charges of $116.6 million in 2017.

Interest expense, net of capitalized interest. Interest expense for the year ended December 31, 2018 was $82.4 million, an increase of $15.9 million, or 24%, compared to the year ended December 31, 2017, primarily due to the higher interest charges of $12.9 million on the 8.50% Senior Notes, as a result of the $125.0 million bond offering in the fourth quarter of 2017, higher interest expense on our revolving credit facility of $6.1 million due to higher interest rates in 2018 compared to 2017, higher interest charges of $0.9 million on the 3.97% Senior Secured Notes due to the acquisition of Trans-Union in November 2017, offset by the favorable position of our interest rate swaps in the amount of $5.1 million.

Other income (expense), net. Other income, net for the year ended December 31, 2018 was $0.6 million, a decrease of $35.7 million, compared to the year ended December 31, 2017, primarily due to the fair value adjustment recorded on the 2017 acquisition of the remaining interests of MPOG.

Income tax expense. Income tax expense for the year ended December 31, 2018 was $33.0 million, an increase of $31.8 million, compared to the year ended December 31, 2017, primarily due to the sale of Marine Products during 2018. With the exception of our Marine Products, the Partnership is not subject to U.S. federal or state income taxes as such income taxes are generally borne by our unitholders. Se further discussion in Note 19. Income Taxes of this 2018 Form 10-K.

Income from discontinued operations, including gain on sale. Income from discontinued operations represents the Partnership's income from the discontinued operations, including gain or loss on sales. Income from discontinued operations, net of tax for the year ended December 31, 2017 of $44.1 million was associated with the sale of the Propane Business on September 1, 2017.

Year ended December 31, 2017 compared to year ended December 31, 2016 (in thousands, except percentages)

	Years Ended December 31,			
	2017	2016	Change	%
Revenue	$651,435	$589,026	$62,409	11 %
Operating expenses:				
Cost of sales	457,371	393,351	64,020	16 %
Direct operating expenses	82,256	71,544	10,712	15 %
Corporate expenses	112,058	89,438	22,620	25 %
Depreciation, amortization and accretion expense	103,448	90,882	12,566	14 %
(Gain) loss on sale of assets, net	(4,063)	688	(4,751)	*
Impairment of long-lived assets and intangible assets	116,609	697	115,912	*
Impairment of goodwill	77,961	2,654	75,307	*
Total operating expenses	945,640	649,254	296,386	46 %
Operating loss	(294,205)	(60,228)	(233,977)	(388)%
Other income (expense), net:				
Interest expense, net of capitalized interest	(66,465)	(21,433)	(45,032)	210 %
Other income, net	36,254	254	36,000	*
Earnings in unconsolidated affiliates	63,050	40,158	22,892	57 %
Loss from continuing operations before income taxes	(261,366)	(41,249)	(220,117)	(534)%
Income tax expense	(1,235)	(2,580)	1,345	52 %
Loss from continuing operations	(262,601)	(43,829)	(218,772)	499 %
Income (loss) from discontinued operations, including gain on sale	44,095	(4,715)	48,810	*
Net loss	(218,506)	(48,544)	(169,962)	350 %
Net income attributable to noncontrolling interests	(4,473)	(2,766)	(1,707)	(62)%
Net loss attributable to the Partnership	$(222,979)	$(51,310)	$(171,669)	335 %
Non-GAAP Financial Measures				
Total Segment gross margin (1)	$244,854	$226,213	$18,641	8 %
Adjusted EBITDA (2)	$176,394	$177,565	$(1,171)	(1)%

*Not a meaningful percentage

(1) For reconciliation of Total Segment gross margin to its nearest GAAP measure, Income from continuing operations before income taxes, see the table in Non-GAAP Financial Measures.

(2) See the table in Non-GAAP Financial Measures for a reconciliation of Adjusted EBITDA to its nearest GAAP measure.

Net loss attributable to the Partnership for the year ended December 31, 2017 was $223.0 million, an increase of $171.7 million, or 335%, from December 31, 2016, primarily due to the following:

- Impairment charges of long-lived assets and intangible assets of $116.6 million;

- goodwill impairment charges of $78.0 million; and
- a $45.0 million increase in interest expense, net of capital interest, primarily due to higher outstanding borrowings under our revolving credit facilities and an increase in our weighted-average interest rate.

The above items, which increased the Net loss attributable to the Partnership between periods, were partially offset by:

- an increase of $36.0 million in other income related to the fair value adjustment recorded in 2017 from the acquisition of the remaining interests of MPOG;
- an increase of $48.8 million in income from discontinued operations, including gain on sale, primarily due to the gain on the sale of our Propane Business in 2017; and
- an increase of $22.9 million in earnings from unconsolidated affiliates.

Total Segment gross margin for the year ended December 31, 2017 was $244.9 million, an increase of $18.6 million, or 8%, compared to the year ended December 31, 2016, primarily due to increases in our Offshore Pipelines and Services and Natural Gas Transportation Services segments offset by decreases in our Gas Gathering and Processing Services, Liquid Pipeline Services and Terminalling Services segments.

Adjusted EBITDA for the year ended December 31, 2017 was $176.4 million, a decrease of $1.2 million, or 1%, compared to the year ended December 31, 2016.

We distributed $89.4 million, or $1.65, per common unit during the year ended December 31, 2017, which represents the distribution for the fourth quarter of 2016 and the first three quarters of 2017, compared to a distribution of $101.6 million during the year ended December 31, 2016.

Please see Results of Operations – Segment Results for a discussion of revenues, cost of sales, direct operating expenses and earning in unconsolidated affiliates.

Corporate expenses. Corporate expenses for the year ended December 31, 2017 were $112.1 million, an increase of $22.6 million, or 25%, compared to the year ended December 31, 2016. This increase was primarily due to transaction related costs associated with the JPE Merger and the SXE Transactions of $14.8 million, $4.0 million in audit and tax fees, $2.7 million in legal and regulatory compliance fees in support of corporate activities, and $1.1 million due to information and technology costs related to systems and licenses that were either implemented or initiated during 2017.

Depreciation, amortization and accretion. Depreciation, amortization and accretion for the year ended December 31, 2017 was $103.4 million, an increase of $12.6 million, or 14%, compared to the year ended December 31, 2016. This increase was primarily due to the acceleration of the accumulated amortization of a JPE customer relationship carried out in the beginning of the first quarter of 2017 through August 2017 for $10.0 million. The remaining difference is primarily related to our Panther acquisition in the third quarter of 2017 and the Trans-Union acquisition in the fourth quarter of 2017.

Impairment of long-lived assets and intangible assets. Impairment of long-lived assets and intangible assets expense for the year ended December 31, 2017 was $116.6 million, an increase of $115.9 million, compared to the year ended December 31, 2016. During the fourth quarter of 2017, we identified certain assets where events or circumstances indicated we may not recover their carrying value. Due to plant shut downs in the quarter and changes in our forecast volumes on certain assets, as part of our annual budget process, we have made operational decisions that impact our ability to recover the carrying value of assets. As a result, asset impairment charges of $116.6 million were recorded in the fourth quarter of 2017, of which $103.9 million was related to our property, plant and equipment and $12.7 million was related to intangible assets. Of the $103.9 million impairment charge to our property, plant and equipment, $97.8 million related to our Gas Gathering and Processing Services segment, $3.9 million related to our Natural Gas Transportation Services segment and $2.2 million related to our Liquid Pipelines and Services segment. Additionally, of the $12.7 million impairment charge to our intangible assets, $10.8 million related to our Gas

Gathering and Services segment and $1.9 million related to our Liquid Pipelines and Services segment.

Impairment of goodwill. Goodwill impairment expense for the year ended December 31, 2017 was $78.0 million, an increase of $75.3 million compared to the year ended December 31, 2016. In 2017, we recognized goodwill impairment charges totaling $78.0 million to our Liquid Pipelines and Services segment. In 2016, we recognized goodwill impairment charges totaling $2.7 million related to our JP Liquids business.

Interest expense, net of capitalized interest. Interest expense, net of capitalized interest for the year ended December 31, 2017 was $66.5 million, an increase of $45.0 million, or 210%, compared to the year ended December 31, 2016. This increase was primarily due to higher outstanding borrowings under our revolving credit facilities and an increase in our weighted average interest rate.

Income (loss) from discontinued operations. Income (loss) from discontinued operations represents the Partnership's income (loss) from the discontinued operations, including gain or loss on sales. Income from discontinued operations, net of tax for the year ended December 31, 2017 of $44.1 million was associated with the sale of the Propane Business on September 1, 2017, whereas loss from discontinued operations, net of tax for the year ended December 31, 2016, of $4.7 million was associated primarily with the sale of the Mid-Continent Business on February 1, 2016. For more information see Item 8. Note 5. Dispositions of this 2018 Form 10-K.

Results of Operations — Segment Results

Gas Gathering and Processing Services Segment

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The table below contains key segment performance indicators for the years ended December 31, 2018 and 2017 related to our Gas Gathering and Processing Services segment (in thousands, except operating data and percentages).

	For the Years Ended December 31,			
	2018	2017	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$131,475	$124,853	$6,622	5 %
Services	44,122	25,399	18,723	74 %
Gains (losses) on commodity derivatives, net	311	(340)	651	(191)%
Cost of sales	124,379	101,981	22,398	22 %
Direct operating expenses	28,000	34,040	(6,040)	(18)%
Other financial data:				
Segment gross margin (1)	$51,888	$48,053	$3,835	8 %
Operating data:				
Average throughput (MMcf/d)	173.9	202.0	(28.1)	(14)%
Average plant inlet volume (MMcf/d) (2)	43.6	95.7	(52.1)	(54)%
Average gross NGL production (Mgal/d) (2)	315.9	325.5	(9.6)	(3)%
Average gross condensate production (Mgal/d) (2)	81.6	64.0	17.6	28 %

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.
(2) Excludes volumes and gross production under our elective processing arrangements.

Commodity sales. Commodity sales for the year ended December 31, 2018 were $131.5 million, an increase of $6.6 million, or 5%, compared to the year ended December 31, 2017, primarily due to the following:

- increased sales of NGLs, natural gas and condensate at the Longview Plant of $5.7 million primarily due to an increase in residue volumes;
- increased marketing activity of $20.9 million due to new contracts and higher prices entered into in 2018;
- increase in sales at the Chatom-Bazor Ridge facility of approximately $6.2 million due to additional condensate deliveries and increased pricing;
- increased sales of NGLs, natural gas and condensate at the Yellow Rose facility in the amount of $7.6 million primarily as a result of increased higher quality throughput and improved recoveries;
- increased sales at our Mesquite facility of $4.8 million; and
-

the increases noted above were partially offset by a $36.3 million reduction in Commodity Sales due to our adoption of Topic 606, in which we determined that certain percentage of proceeds (“POP”) contracts should be recorded on a net basis instead of a gross basis. For more information on our adoption of Topic 606, see Part II. Item 8. Note 2. New Accounting Pronouncements of this 2018 Form 10-K and a reduction of volumes across several other assets of $2.0 million.

Services. Services for the year ended December 31, 2018 were $44.1 million, an increase of $18.7 million, or 74%, compared to the year ended December 31, 2017, due to increased fee revenue primarily on Yellow Rose, Chapel Hill and Lavaca of $5.5 million. Additionally, as a result of our adoption of Topic 606, we have determined that certain POP contracts should be recorded on a net basis, resulting in a $15.3 million increase in Services revenue. Offsetting these increases is a decrease in revenue for AMID NGL Trucking of $2.3 million, primarily due to expired contracts during the year.

Cost of sales. Cost of sales for the year ended December 31, 2018 were $124.4 million, an increase of $22.4 million, or 22%, compared to the year ended December 31, 2017, primarily due to increased sales of NGLs, natural gas and condensate sales at the Longview, Yellow Rose and Chatom-Bazor Ridge facilities of $42.5 million. These increases were partially offset by $20.5 million due to Topic 606 implementation as discussed above.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2018 were $28.0 million, a decrease of $6.0 million, or 18%, compared to the year ended December 31, 2017, primarily due to $4.3 million in lower operating expenses at East Texas and Burns Point, a decrease of $1.0 million in labor expenses primarily due to an increase in capitalized labor allocation and reductions of $0.4 million in lease and rent expenses and $0.3 million in vehicle expenses.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The table below contains key segment performance indicators for the years ended December 31, 2017 and 2016 related to our Gas Gathering and Processing Services segment (in thousands, except operating data and percentages).

	For the Years Ended December 31,			
	2017	2016	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$124,853	$91,444	$33,409	37 %
Services	25,399	29,476	(4,077)	(14)%
Losses on commodity derivatives, net	(340)	(833)	493	(59)%
Cost of sales	101,981	68,955	33,026	48 %
Direct operating expenses	34,040	35,276	(1,236)	(4)%
Other financial data:				
Segment gross margin (1)	$48,053	$50,040	$(1,987)	(4)%
Operating data:				
Average throughput (MMcf/d)	202.0	220.6	(18.6)	(8)%
Average plant inlet volume (MMcf/d) (2)	95.7	102.1	(6.4)	(6)%
Average gross NGL production (Mgal/d) (2)	325.5	192.9	132.6	69 %
Average gross condensate production (Mgal/d) (2)	64.0	82.9	(18.9)	(23)%

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

(2) Excludes volumes and gross production under our elective processing arrangements.

Commodity sales. Commodity sales for the year ended December 31, 2017 were $124.9 million, an increase of $33.4 million, or 37%, compared to the year ended December 31, 2016. This increase was primarily due to the following:

- increased revenue from sales of NGLs and condensate at the Longview plant of $44.4 million due to three new contracts, two of which started in the first quarter of 2017 and one ongoing contract; and

- offsetting this was reduced NGL and condensate volumes at our Chatom/Bazor Ridge plants of $11.5 million due to lower system volumes from production declines and the loss of Y-grade product and plant downtime in the fourth quarter of 2017.

Services. Services for the year ended December 31, 2017 were $25.4 million, a decrease of $4.1 million, or 14%, compared to the year ended December 31, 2016, primarily driven by reduction in third party trucking revenue of $3.4 million and lower drilling activity resulting in a decline in compression and gathering charges of $1.7 million on Lavaca, offset by an increase from a pipeline recovery fee of $1.3 million at Chatom/Bazor Ridge.

Cost of sales. Cost of sales for the year ended December 31, 2017 were $102.0 million, an increase of $33.0 million, or 48%, compared to the year ended December 31, 2016, primarily due to increase of NGL, natural gas and condensate sales at the Longview plant, as mentioned above in Commodity sales, offset by reduced NGL and condensate volumes at Chatom/Bazor Ridge.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2017 were $34.0 million, a decrease of $1.2 million, or 4%, compared to the year ended December 31, 2016, primarily due to lower compressor rentals for $0.8 million due to our ongoing cost cutting efforts and a $0.7 million decrease in outside services at our Longview facility, offset by an increase in vehicle diesel and lubricants costs associated with our NGL Trucking asset.

Liquid Pipelines and Services Segment

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The table below contains key segment performance indicators for the years ended December 31, 2018 and 2017 related to our Liquid Pipelines and Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2018	2017	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$428,977	$319,870	$109,107	34 %
Services	21,538	23,854	(2,316)	(10)%
Gains on commodity derivatives, net	1,725	221	1,504	681 %
Earnings in unconsolidated affiliates	11,954	5,226	6,728	129 %
Cost of sales	423,519	309,166	114,353	37 %
Direct operating expenses	11,162	13,061	(1,899)	(15)%
Other financial data:				
Segment gross margin [(1)]	$40,542	$39,870	$672	2 %
Operating data [(2)] :				
Average throughput Pipeline (Bbl/d)	36,408	34,248	2,160	6 %
Average throughput Truck (Bbl/d)	3,545	2,910	635	22 %

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.
(2) Excludes volumes from our equity investments.

Commodity sales. Commodity sales for the year ended December 31, 2018 were $429.0 million, an increase of $109.1 million, or 34%, compared to the year ended December 31, 2017, primarily due to a $48.0 million increase on COSL as a result of increased volumes and $68.9 million due to a higher favorable average price increase of $9.33/Bbl during 2018 compared to 2017. Offsetting the overall increase in commodity sales is a reduction in Marketing contracts of $6.2 million and reduction in volumes of $1.4 million on Bakken.

Services. Services for the year ended December 31, 2018 were $21.5 million, a decrease of $2.3 million, or 10%, compared to the year ended December 31, 2017, primarily due to a $7.6 million decrease at our Cushing facility as a result of declining tank utilization and the termination of a contract offset by an increase of $3.5 million due to a new trucking contract in 2018 and an increase in COSL volumes of $1.6 million.

Earnings in unconsolidated affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2018 were $12.0 million, an increase of $6.7 million, or 129%, compared to the year ended December 31, 2017, primarily due to our 50% interest in Cayenne which began operating in December 2017.

Cost of sales. Cost of sales for the year ended December 31, 2018 were $423.5 million, an increase of $114.4 million, or 37%, compared to the year ended December 31, 2017, primarily resulting from higher volumes and higher prices achieved on the

Marketing and COSL assets of $115.9 million and increased trucking volumes and related expenses of $5.2 million. Offsetting these increases is a decrease of $6.9 million related to Marketing contracts.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2018 were $11.2 million, a decrease of $1.9 million, or 15%, compared to the year ended December 31, 2017, primarily due to decreases of $0.7 million associated with our Crude Trucking bulk purchases of vehicle diesel and lubricants, $0.7 million of repair and maintenance expenses and $0.5 million of insurance expenses.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The table below contains key segment performance indicators for the years ended December 31, 2017 and 2016 related to our Liquid Pipelines and Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2017	2016	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$319,870	$304,502	$15,368	5 %
Services	23,854	26,785	(2,931)	(11)%
Gains (losses) on commodity derivatives, net	221	(341)	562	(165)%
Earnings in unconsolidated affiliates	5,226	2,070	3,156	152 %
Cost of sales	309,166	288,735	20,431	7 %
Direct operating expenses	13,061	11,195	1,866	17 %
Other financial data:				
Segment gross margin (1)	$39,870	$44,161	$(4,291)	(10)%
Operating data (2) :				
Average throughput Pipeline (Bbl/d)	34,248	32,257	1,991	6 %
Average throughput Truck (Bbl/d)	2,910	1,628	1,282	79 %

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.
(2) Excludes volumes from our equity investments.

Commodity sales. Commodity sales for the year ended December 31, 2017 were $319.9 million, an increase of $15.4 million, or 5%, compared to the year ended December 31, 2016, primarily due to a net increase in marketing contracts.

Services. Services for the year ended December 31, 2017 were $23.9 million, a decrease of $2.9 million, or 11%, compared to the year ended December 31, 2016. This decrease was primarily due to a $3.6 million reduction in storage and utilization at our Cushing terminal from a new contract with lower storage and rate terms offset by a $0.7 million increase due to new exploration and production wells coming on-line in 2017 and associated capital recovery fees.

Cost of sales. Cost of sales for the year ended December 31, 2017 were $309.2 million, an increase of $20.4 million, or 7%, compared to the year ended December 31, 2016, primarily due to the net increase in marketing contracts.

Earnings in unconsolidated affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2017 were $5.2 million, an increase of $3.2 million, or 152% compared to the year ended December 31, 2016, primarily driven by increasing volumes on Tri-States and Wilprise due to the new wells (production) from the Thunderhorse platform.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2017 were $13.1 million, an increase of $1.9 million, or 17%, compared to the year ended December 31, 2016, primarily attributable to an increase in employee headcount and contract services at Silver Dollar.

Natural Gas Transportation Services Segment

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The table below contains key segment performance indicators for the years ended December 31, 2018 and 2017 related to our Natural Gas Transportation Services segment (in thousands, except operating data and percentages).

	For the Years Ended December 31,			
	2018	2017	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$25,617	$25,376	$241	1 %
Services	34,046	22,523	11,523	51 %
Cost of sales	23,207	24,516	(1,309)	(5)%
Direct operating expenses	8,272	6,244	2,028	32 %
Other financial data:				
Segment gross margin [(1)]	$36,130	$23,005	$13,125	57 %
Operating data:				
Average throughput (MMcf/d)	678.9	420.4	258.5	61 %

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

Commodity sales. Commodity sales for the year ended December 31, 2018 were $25.6 million, an increase of $0.2 million, or 1%, compared to the year ended December 31, 2017, primarily due to increased volumes.

Services. Services for the year ended December 31, 2018 were $34.0 million, an increase of $11.5 million, or 51%, compared to the year ended December 31, 2017, primarily due to an increase of $7.6 million resulting from our Trans-Union acquisition in the fourth quarter of 2017, an increase of $2.2 million due to our adoption of Topic 606, an increase in imbalance activity of $1.5 million, and a $1.0 million increase in management fees, offset by a $0.9 million decrease in firm transportation contracts.

Cost of sales. Cost of sales for the year ended December 31, 2018 were $23.2 million, a decrease of $1.3 million, or 5%, compared to the year ended December 31, 2017, primarily due to lower volumes related to the Magnolia system.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2018 were $8.3 million, an increase of $2.0 million, or 32%, compared to the year ended December 31, 2017, primarily attributable to a $1.2 million lost and unaccounted for line pack recovery recognized in 2017 for AlaTenn and Bamagas, $0.6 million in litigation fees for Magnolia in 2018 and a $0.2 million increase in repairs and maintenance.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The table below contains key segment performance indicators for the years ended December 31, 2017 and 2016 related to our Natural Gas Transportation Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2017	2016	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$25,376	$21,999	$3,377	15%
Services	22,523	18,109	4,414	24%
Cost of sales	24,516	21,288	3,228	15%
Direct operating expenses	6,244	5,923	321	5 %
Other financial data:				
Segment gross margin (1)	$23,005	$18,616	$4,389	24%
Operating data:				
Average throughput (MMcf/d)	420.4	389.9	30.5	8 %

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

Commodity sales. Commodity sales for the year ended December 31, 2017 were $25.4 million, an increase of $3.4 million, or 15%, compared to the year ended December 31, 2016, primarily due to higher average index prices on Magnolia.

Services. Services for the year ended December 31, 2017 were $22.5 million, an increase of $4.4 million, or 24%, compared to the year ended December 31, 2016. This increase was primarily due to new firm transportation contracts of 150 MMcf/d on our MLGT pipeline for $1.6 million, $1.0 million on our new Midla Natchez line from contracts with higher rates, $1.0 million as a result of the Trans-Union acquisition in November 2017 and $0.7 million from additional contracts on AlaTenn.

Cost of sales. Cost of sales for the year ended December 31, 2017 were $24.5 million, an increase of $3.2 million, or 15%, compared to the year ended December 31, 2016, primarily due to higher average index prices on Magnolia.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2017 were $6.2 million, an increase of $0.3 million, or 5%, compared to the year ended December 31, 2016, primarily due to employee and contractor costs.

Offshore Pipelines and Services Segment

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The table below contains key segment performance indicators for the years ended December 31, 2018 and 2017 related to our Offshore Pipelines and Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2018	2017	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$10,886	$11,508	$(622)	(5)%
Services	61,294	43,630	17,664	40 %
Earnings in unconsolidated affiliates	69,975	57,825	12,150	21 %
Cost of sales	8,050	8,993	(943)	(10)%
Direct operating expenses	30,578	17,040	13,538	79 %
Other financial data:				
Segment gross margin (1)	$134,106	$103,970	$30,136	29 %
Operating data (2):				
Average throughput (MMcf/d)	310.7	309.6	1.1	— %

---

(1) See Item 8. Note 23. Reportable Segments of this Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

(2) Excludes volumes from our unconsolidated affiliates.

Commodity sales. Commodity sales for the year ended December 31, 2018 were $10.9 million, a decrease of $0.6 million, or 5%, compared to the year ended December 31, 2017, primarily due to lower volumes at our Gloria-Lafitte system partially offset by an increase in sales from the acquisition of Panther in the third quarter of 2017.

Services. Services for the year ended December 31, 2018 were $61.3 million, an increase of $17.7 million, or 40%, compared to the year ended December 31, 2017, primarily due to the impact of acquisitions in the third quarter of 2017 of $15.0 million and additional volumes due to product rerouted from the Williams system at High Point Gas Gathering of $4.3 million. These increases were partially offset by shipper imbalances on our Gloria-Lafitte system which reduced revenues by $1.0 million.

Earnings in unconsolidated affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2018 were $70.0 million, an increase of $12.2 million, or 21%, compared to the year ended December 31, 2017, primarily due to increases in equity interest of Delta House in September 2017 and Destin in October 2017 and increased production between periods from Destin and Okeanos, offset by temporary curtailment of production flows on Delta House as certain third-party owned upstream infrastructure required remediation work.

Cost of sales. Cost of sales for the year ended December 31, 2018 were $8.1 million, a decrease of $0.9 million, or 10%, compared to the year ended December 31, 2017, primarily due to reductions from decreased production on our Gloria-Lafitte system of $3.8 million, partially offset by increased costs from Panther, which was acquired in the third quarter of 2017, of $3.2 million.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2018 were $30.6 million, an increase of $13.5 million, or 79%, compared to the year ended December 31, 2017, primarily due to increased operating expenses associated with the acquisition of Panther Pipelines.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The table below contains key segment performance indicators for the years ended December 31, 2017 and 2016 related to our Offshore Pipelines and Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2017	2016	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$11,508	$6,812	$4,696	69 %
Services	43,630	40,502	3,128	8 %
Loss on commodity derivatives, net	—	(7)	7	*
Earnings in unconsolidated affiliates	57,825	38,088	19,737	52 %
Cost of sales	8,993	3,049	5,944	195 %
Direct operating expenses	17,040	10,945	6,095	56 %
Other financial data:				
Segment gross margin (1)	$103,970	$82,346	$21,624	26 %
Operating data (2):				
Average throughput (MMcf/d)	309.6	466.4	(156.8)	(34)%

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

(2) Excludes volumes from our unconsolidated affiliates.

Commodity sales. Commodity sales for the year ended December 31, 2017 were $11.5 million, an increase of $4.7 million, or 69%, compared to the year ended December 31, 2016, primarily due to a new well in December 2016 at Mud Lake, Louisiana on our Gloria system.

Services. Services for the year ended December 31, 2017 were $43.6 million, an increase of $3.1 million, or 8%, compared to the year ended December 31, 2016, primarily due to $7.0 million of higher management fees on AmPan, and $5.3 million due to the acquisition of VKGS in June 2017, offset by a $10.0 million reduction on HPGT resulting from the shut-in of the dry line, firm transportation contract expiration, Hurricane Nate impacts, and compressor maintenance.

Cost of sales. Cost of sales for the year ended December 31, 2017 were $9.0 million, an increase of $5.9 million, or 195%, compared to the year ended December 31, 2016, primarily due to the addition of a new well in December 2016 at Mud Lake, Louisiana on our Gloria system for $3.6 million, $1.2 million due to imbalances on HPGT, $0.6 million of additional cost on Quivira as a result of a new condensate contract in November 2017, and $0.5 million due to the acquisition of VKGS in June 2017.

Earnings in unconsolidated affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2017 were $57.8 million, an increase of $19.7 million, or 52%, compared to the year ended December 31, 2016, primarily due to the incremental ownership in Delta House in the fourth quarter of 2016 and our subsequent increases in ownership in November 2017 for $11.2 million, $5.4 million on Destin as a result of twelve months of ownership reflected in 2017 versus eight months in 2016, as well as higher volumes on our Okeanos system for $4.0 million.

In the fourth quarter of 2017, a temporary delay of production volumes flowing into Delta House occurred, requiring remedial work which was completed during the third quarter of 2018. This resulted in a reduction in cash distributions from Delta House. On March 11, 2018, the Partnership and Magnolia, an affiliate of ArcLight, entered into a Capital

Contribution Agreement by which Magnolia will provide additional capital and corporate overhead support to the Partnership for the first three quarters of 2018 in an amount up to the difference between the actual cash distribution received by the Partnership on account of its interest in Delta House and the quarterly cash distribution expected to be received if production flows to Delta House had not been not curtailed.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2017 were $17.0 million, an increase of $6.1 million, or 56%, compared to the year ended December 31, 2016, primarily due to $3.9 million incremental expenses associated with our recent acquisitions (VKGS, $2.3 million, and Panther, $1.6 million), $1.5 million in environmental regulatory and compliance costs, and $0.7 million due to rental equipment costs.

Terminalling Services Segment

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

The table below contains key segment performance indicators for the years ended December 31, 2018 and 2017 related to our Terminalling Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2018	2017	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$13,087	$15,295	$(2,208)	(14)%
Services	32,276	39,246	(6,970)	(18)%
Cost of sales	12,885	12,715	170	1 %
Direct operating expenses	9,664	11,870	(2,206)	(19)%
Other financial data:				
Segment gross margin (1)	$22,814	$29,956	$(7,142)	(24)%

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

Commodity sales. Commodity sales for the year ended December 31, 2018 were $13.1 million, a decrease of $2.2 million, or 14%, compared to the year ended December 31, 2017, primarily due to lower volumes at the Caddo Mills and North Little Rock terminals.

Services. Services for the year ended December 31, 2018 were $32.3 million, a decrease of $7.0 million, or 18%, compared to the year ended December 31, 2017, primarily driven by a $10.5 million reduction in service revenue related to the disposition of our Marine Products and Refined Products assets during 2018 offset by an increase of $3.5 million due to the adoption of Topic 606.

Cost of sales. Cost of sales for the year ended December 31, 2018 were $12.9 million, an increase of $0.2 million, or 1%, compared to the year ended December 31, 2017, primarily due to the adoption of Topic 606 which increased costs by approximately $2.1 million offset by reductions due to the disposition of Marine Products and Refined Products assets during 2018.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2018 were $9.7 million, a decrease of $2.2 million, or 19%, compared to the year ended December 31, 2017, primarily due to lower operating costs as a result of the 2018 divestiture of Harvey, Brunswick and Westwego terminals.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The table below contains key segment performance indicators for the years ended December 31, 2017 and 2016 related to our Terminalling Services segment (in thousands, except operating data and percentages).

	For the Year Ended December 31,			
	2017	2016	Change	%
Segment Financial and Operating Data:				
Financial data:				
Commodity sales	$15,295	$14,655	$640	4 %
Services	39,246	36,359	2,887	8 %
Loss on commodity derivatives, net	—	(436)	436	*
Cost of sales	12,715	11,324	1,391	12 %
Direct operating expenses	11,870	8,205	3,665	45 %
Other financial data:				
Segment gross margin (1)	$29,956	$31,050	$(1,094)	(4)%

(1) See Item 8. Note 23. Reportable Segments of this 2018 Form 10-K for a reconciliation of Segment Gross Margin to Income from continuing operations before income taxes.

Commodity sales. Commodity sales for the year ended December 31, 2017 were $15.3 million, an increase of $0.6 million, or 4%, compared to the year ended December 31, 2016. The increase relates to our refined products and was primarily driven by an increase in butane blending sales pricing at our Caddo Mills for $1.2 million offset by a decrease in butane blending volumes sold at our North Little Rock terminal facility for $0.6 million.

Services. Services for the year ended December 31, 2017 were $39.2 million, an increase of $2.9 million, or 8%, compared to the year ended December 31, 2016, primarily attributable to a $1.8 million increase in throughput revenues from Caddo Mills facility enhancements and a $1.7 million increase in contracted capacity and related ancillary services as a result of the Harvey terminal expansion offset by a $0.5 million decrease in throughput revenue at our North Little Rock terminal due to the loss of a customer in July 2016.

Cost of sales. Cost of sales for the year ended December 31, 2017 were $12.7 million, an increase of $1.4 million, or 12%, compared to the year ended December 31, 2016, primarily due to higher butane costs.

Direct operating expenses. Direct operating expenses for the year ended December 31, 2017 were $11.9 million, an increase of $3.7 million, or 45%, compared to the year ended December 31, 2016. The increase was primarily due to a $2.5 million increase in operating costs at our Harvey terminal and driven by $1.1 million increase in repairs and maintenance, contractor services, environmental and related costs directly attributable to the Harvey facility expansion.

Liquidity and Capital Resources

Overview

Our business is capital intensive and requires significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities.

Our sources of liquidity are:

- cash flows from operating activities;
- cash distributions from our unconsolidated affiliates;
- borrowings under our Credit Agreement;
- proceeds from asset sales;
- proceeds from private and public offerings of debt;
- issuances of letters of credit in lieu of prepayments; and

•issuances of additional common units, preferred units or other securities.

Not all of these sources will be available to us at all times, or on terms acceptable to us. However, we believe cash generated from these sources will be sufficient to meet our short-term working capital requirements and medium-term maintenance capital expenditure requirements. However, if we are unable to extend, replace or refinance our Credit Agreement, there is substantial doubt about our ability to continue as a going concern. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, additional forms of secured or unsecured debt or preferred equity financing, if available. In addition, we would reduce non-essential capital expenditures, controllable direct operating expenses and corporate expenses, as necessary. We plan to finance our growth capital expenditures primarily from the sale of non-core assets and through additional forms of debt or equity financing, if possible. Availability and terms of any financing or asset sales depend on market and other conditions, many of which are beyond our control. We may not be able to access financing or complete asset sales as, and when, desired.

Changes in natural gas, crude oil, NGL and condensate prices and the terms of our contracts may have a direct impact on our generation and use of cash from operations due to their impact on net income (loss), along with the resulting changes in working capital. In the past, we mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, see the information provided under Item 7A. Quantitative and Qualitative Disclosures about Market Risk of this 2018 Form 10-K. Our cash flow may also be adversely impacted by disruptions to operations, reduced distributions from equity investments and actions of third parties we cannot control.

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

Going Concern Assessment

Our Credit Agreement matures on September 5, 2019 and has not been renewed as of the date of the issuance of these consolidated financial statements. While the Partnership intends to renew or extend the terms of its Credit Agreement, until such time as we have executed an agreement to refinance or extend the maturity of our Credit Agreement, we cannot conclude that it is probable we will do so, and accordingly, this raises substantial doubt about our ability to continue as a going concern. See Going Concern Assessment and Management's Plans above for more information.

AMID Revolving Credit Agreement

On March 8, 2017, we entered into the Original Credit Agreement, with Bank of America N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders, which had an initial borrowing commitment of $900 million and provided for an accordion feature that would permit, subject to customary conditions, the borrowing commitment under the facility to be increased to a maximum of $1.1 billion. As a result of the Amendments, discussed below, the borrowing commitment under the Credit Agreement was $620 million at December 31, 2018.

The Credit Agreement matures on September 5, 2019, and therefore, is being presented as a current liability in our Consolidated Balance Sheet as of December 31, 2018.

During 2018, we amended the Original Credit Agreement by entering into the Amendments with a syndicate of lenders and Bank of America, N.A., as administrative agent. The Amendments add a required prepayment in the amount equal to 100% of the net cash proceeds received from the Marine Products and Refined Products asset sales and any other disposition greater than $5 million.

The Amendments also amend our borrowing commitment as follows:

- upon consummation of the Marine Products sale, the aggregate commitment under the Credit Agreement was automatically reduced by $200.0 million;

- upon consummation of the Refined Products sale, the aggregate commitment under the Credit Agreement was automatically reduced by $80.0 million; and
- upon consummation of any disposition greater than $7.5 million, the aggregate commitment under the Credit Agreement shall be automatically reduced by 50% of the net cash proceeds of such disposition.

The Amendments add new pricing tiers of LIBOR + 3.50% when Consolidated Total Leverage Ratio equals or exceeds 5.0:1.0 and LIBOR + 4.00% when Consolidated Total Leverage Ratio equals or exceeds 5.5:1.0. The Credit Agreement includes the following financial covenants, as amended by the Amendments and defined in the Credit Agreement, which financial covenants will be tested on a quarterly basis, for the fiscal quarter then ending:

	Minimum Consolidated Interest Coverage Ratio	Maximum Consolidated Total Leverage Ratio	Maximum Consolidated Secured Leverage Ratio
December 31, 2018	1.75:1.00	6.25:1.00	3.75:1.00
March 31, 2019	1.75:1.00	6.50:1.00	3.75:1.00
June 30, 2019 and thereafter	1.50:1.00	5.75:1.00	3.50:1.00

As of December 31, 2018, we were in compliance with our Credit Agreement financial covenants, including those shown below:

Ratio	Actual
Consolidated Interest Coverage Ratio	2.12
Consolidated Total Leverage Ratio	5.79
Consolidated Secured Leverage Ratio	3.17

Our ability to maintain compliance with the leverage and interest coverage ratios included in the Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions or drop down transactions, as well as the associated financing for such initiatives. The terms of the Credit Agreement also include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. If required, ArcLight, which controls the General Partner of the Partnership, has confirmed its intent to provide financial support for the Partnership to maintain compliance with the covenants contained in the Credit Agreement through April 10, 2019.

As of December 31, 2018, we had $514.8 million of borrowings, $39.3 million of letters of credit outstanding and $65.9 million of remaining borrowing commitment under the Credit Agreement, of which $39.8 million was available as of December 31, 2018. For the years ended December 31, 2018, 2017 and 2016, the weighted average interest rate, excluding the impact of interest rate swaps, on borrowings under this facility was 6.47%, 4.96% and 4.29%, respectively.

On July 31, 2018, we completed the sale of Marine Products. Net proceeds from this disposition were approximately $208.6 million, exclusive of $5.7 million in advisory fees and other costs, and were used to pay down the Credit Agreement.
On December 20, 2018, we completed the sale of Refined Products. Net proceeds from this disposition were $125 million, exclusive of $3.7 million in advisory fees and other costs, and were used to pay down the Credit Agreement. For additional information see Item 8. Note 5. Dispositions of this 2018 Form 10-K.
For additional information relating to our outstanding debt see Item 8. Note 14. Debt Obligations of this 2018 Form 10-K.

JPE Revolver

JPE had a $275.0 million revolving loan, which included a sub-limit of up to $100.0 million for letters of credit with Bank of America, N.A. (the "JPE Revolver"). The JPE Revolver was scheduled to mature on February 12, 2019, but on March 8, 2017, in connection with the closing of the JPE Merger, the $199.5 million outstanding balance of the JPE Revolver was paid off in full and terminated. For the year ended December 31, 2017, the weighted average interest rate on borrowings under the JPE Revolver was approximately 2.85%.

8.50% Senior Unsecured Notes

On December 28, 2016, the Partnership and American Midstream Finance Corporation, our wholly-owned subsidiary (the "Co-Issuer" and together with the Partnership, the "Issuers"), completed the issuance and sale of the $300 million aggregate principal amount of their 8.50% Senior Notes due 2021 (the "8.50% Senior Notes"). The 8.50% Senior Notes rank equal in right of payment with all existing and future senior indebtedness of the Issuers, and senior in right of payment to any future subordinated indebtedness of the Issuers. The 8.50% Senior Notes were issued at par and provided approximately $291.3 million in proceeds, after deducting the initial purchasers' discount of $6.0 million and $2.7 million of debt issuance costs.

The 8.50% Senior Notes were offered and sold to qualified institutional buyers in the United States pursuant to Rule 144A under the Securities Act, and to persons, other than U.S. persons, outside the United States pursuant to Regulation S under the Securities Act. Upon the closing of the JPE Merger and the satisfaction of other conditions related thereto, the proceeds were used to repay and terminate the JPE Revolver and reduce borrowings under our Credit Agreement.

On December 19, 2017, the Issuers completed the issuance and sale of an additional $125 million in aggregate principal amount of 8.50% Senior Notes (the "Additional Issuance"), net of issuance cost of approximately $3.0 million. The Additional Issuance was offered and sold to qualified institutional buyers in the United States pursuant to Rule 144A under the Securities Act, and to persons, other than U.S. persons, outside the United States pursuant to Regulation S under the Securities Act.

The 8.50% Senior Notes will mature on December 15, 2021 and interest on the Additional Issuance will accrue from December 15, 2017. Interest on the 8.50% Senior Notes is payable in cash semiannually in arrears on each June 15 and December 15, with interest payable on the Additional Issuance commencing June 15, 2018. Interest will be payable to holders of record on June 1st and December 1st immediately preceding the related interest payment date and will be computed on the basis of a 360-day year consisting of twelve 30-day months. Pursuant to the registration rights agreements entered into in connection with the issuances of the 8.50% Senior Notes, additional interest on the 8.50% Senior Notes accrues at 0.25% per annum for the first 90-day period following December 23, 2017 and by an additional 0.25% per annum with respect to each subsequent 90-day period, up to a maximum additional rate of 1.00% per annum over 8.50%, until we complete an exchange offer for the 8.50% Senior Notes. For further discussion of the 8.50% Senior Notes, see Item 8. Note 14. Debt Obligations of this 2018 Form 10-K.

3.77% Senior Secured Notes

On September 30, 2016, Midla Financing ("Midla Financing") American Midstream (Midla) LLC ("Midla"), and MLGT (together with Midla, the "Note Guarantors") entered into the 3.77% Senior Note Purchase and Guaranty Agreement (the "Note Purchase Agreement") with the purchasers party thereto (the "Purchasers"). Pursuant to the Note Purchase Agreement, Midla Financing issued and sold $60.0 million in aggregate principal amount of 3.77% Senior Notes (non-recourse) due June 30, 2031 (the "3.77% Senior Notes") to the Purchasers, which bear interest at an annual rate of 3.77% to be paid quarterly. The average quarterly principal payment is approximately $1.1 million. Principal on the

3.77% Senior Notes will be paid on the last business day of each fiscal quarter end which began June 30, 2017. The 3.77% Senior Notes are payable in full on June 30, 2031. The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million after deducting related issuance costs of $2.3 million. The 3.77% Senior Notes are non-recourse to the Partnership.

In connection with the Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing's obligations under the Note Purchase Agreement. Also, Midla Financing and the Note Guarantors granted a security interest in substantially all of their tangible and intangible personal property, including the membership interests in each Note Guarantor held by Midla Financing, and Financing Holdings pledged the membership interests in Midla Financing to the Collateral Agent.

Net proceeds from the 3.77% Senior Notes are restricted and have been be used (1) to fund project costs incurred in connection with (a) the construction of the Midla-Natchez Line (b) the retirement of Midla's existing 1920's vintage pipeline (c) the move of our Baton Rouge operations to the MLGT system, and (d) the reconfiguration of the DeSiard compression system and all related ancillary facilities, (2) to pay transaction fees and expenses in connection with the issuance of the 3.77% Senior Notes, and (3) for other general corporate purposes of Midla Financing. In addition, revenue is required to be deposited into restricted cash accounts and disbursements must be approved by the lender. As of December 31, 2018 and December 31, 2017, Restricted cash included $23.4 million and $14.9 million related to the 3.77% Senior Notes. For further discussion of the 3.77% Senior Notes see Item 8. Note 14. Debt Obligations of this 2018 Form 10-K.

3.97% Trans-Union Senior Secured Notes

On May 10, 2016, Trans-Union Interstate Pipeline, LP ("Trans-Union") entered into an agreement with certain institutional investors in the insurance business represented by Babson Capital Management LLC (the "lender") whereby Trans-Union issued $35.0 million in aggregate principal amount of 3.97% Senior Secured Notes ("Trans-Union Senior Notes") due December 31, 2032. Principal and interest on the Trans-Union Senior Notes were payable in installments on the last business day of each quarter beginning June 30, 2016 with the remaining balance payable in full on December 31, 2032. The average quarterly principal payment is approximately $0.5 million. The Trans-Union Senior Notes were issued at par and provided net proceeds of approximately $34.6 million after deducting related issuance cost of approximately $0.4 million. The Partnership assumed the Trans-Union Senior Notes following the Trans-Union acquisition on November 3, 2017. See Note 4. Acquisitions.

The Trans-Union Senior Notes also required pledged accounts in which revenue is required to be deposited into these accounts and disbursements must be approved by the lender. As of December 31, 2018 and 2017, we had $6.8 million and $1.7 million, respectively in Restricted cash in our Consolidated Balance Sheets. For further discussion of the 3.97% Senior Notes see Item 8. Note 14. Debt Obligations of this 2018 Form 10-K.

ArcLight and Affiliates Support

During 2017, affiliates of ArcLight agreed and provided distribution support of $25.0 million pursuant to the support agreement that was executed in conjunction with the JPE Merger. Independent of this agreement, affiliates of ArcLight agreed to provide an additional $9.6 million in support related to the JPE Merger. For further information related to the JPE Merger and distribution support agreement see Item 8. Note 4. Acquisitions of this 2018 Form 10-K. In addition, our General Partner also agreed to absorb $17.6 million corporate overhead expenses. During 2017, ArcLight and its affiliates contributed $15.2 million of the $25.0 million support agreement, $9.6 million related to additional JPE support and $17.6 million related to corporate overhead expense support, which provided $42.4 million to Financing activities in our Consolidated Statements of Cash Flows for 2017. In the first quarter of 2018, we received the remaining $9.8 million of the $25.0 million pledged support.

On March 11, 2018, the Partnership and Magnolia, an affiliate of ArcLight, entered into a Capital Contribution Agreement (the “Capital Contribution Agreement”) pursuant to which Magnolia could elect to provide additional capital and overhead support to us during the first three quarters of 2018 in connection with temporary curtailment of production flows at Delta House. During 2018, we received $21.9 million in accordance with this agreement. We expect distributions from Delta House to improve in 2019, as compared to 2018, assuming normal production flows and from the satisfaction of debt service obligations at Delta House. Debt service payments of Delta House totaled approximately $39.8 million in 2018, of which, approximately $14.2 million represents our prorated interest. See Item 1A. Risk Factors. Risks Related to Our Business-A significant portion of our cash flows come from our joint ventures in which we often hold a non-controlling minority ownership position. We may experience reductions in cash flows from our joint ventures due to contractual step-downs in cash distributions, operational or other issues that are beyond our control. We may acquire similar non-controlling minority ownership positions in joint ventures in the future.

Working Capital

We had a working capital deficit of $505.9 million as of December 31, 2018 due to the presentation of our revolving credit facility, which matures on September 5, 2019, as a short term liability. As discussed in Going Concern and Management's Plans, we expect to execute a new revolving credit facility prior to the maturity of our current agreement. For a discussion of risks associated with executing a new revolving credit facility, see Part I. Item 1A. Risk Factors of this 2018 Form 10-K. As of December 31, 2017, we had working capital of $16.2 million.

Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted to a certain extent by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices as both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital as we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Please see Going Concern Assessment and Management's Plans above for a discussion on our ability to continue as a going concern.

Cash Flows

The following table reflects cash flows for the applicable periods (in thousands):

	For the Years Ended December 31, 2017		
	2018	2017	2016
Net cash provided by (used in):			
Operating activities	$5,175	$9,620	$90,351
Investing activities	248,800	(40,491)	(245,689)
Financing activities	(243,134)	(264,180)	477,544

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Operating Activities. For the year ended December 31, 2018, net cash provided by operating activities was $5.2 million, a decrease of $4.4 million compared to the year ended December 31, 2017, primarily due to an increase in net loss of $22.0 million, excluding the effects of noncash adjustments including impairment charges and gains. Offsetting the decrease is an increase of $17.5 million due the changes in operating assets and liabilities.

Investing Activities. For the year ended December 31, 2018, net cash provided by investing activities was $248.8 million, an increase of $289.3 million compared to the year ended December 31, 2017. The increase of cash flows from investing activities resulted primarily from an increase in the proceeds from the sale of assets and business related to the sale of our Marine Products and Refined Products assets of $161.7 million and a reduction in acquisition activity of $76.2 million during 2018. In addition, we both contributed less to and received less from our unconsolidated affiliates which provided an increase in cash flows of $63.3 million. These increases were partially offset by additional cash outflows for the purchase of property, plant and equipment of $11.6 million.

Financing Activities. For the year ended December 31, 2018, net cash used by financing activities was $243.1 million, a decrease of $21.0 million compared to the year ended December 31, 2017. The decline in cash used in financing activities was primarily driven the benefit of a $120.8 million absence in the current year of unitholder distributions for common control transactions associated with Delta House and Series D preferred unit redemptions. In addition, a $36.0 million reduction in cash distributed to our General Partner and $7.3 million net reduction in our cash outflows for our Credit Agreement positively contributed to our overall reduction in cash used by financing activities. Offsetting these positive changes in our cash outflow was the absence in the current year of $128.0 million in proceeds from our 8.50% Senior Notes and a reduction in contributions of $14.5 million.

Year Ended December 31, 2017, Compared to Year Ended December 31, 2016

Operating Activities. For the year ended December 31, 2017, net cash provided by operating activities was $9.6 million, a decrease of $80.7 million compared to the year ended December 31, 2016. The decrease in cash flows from operating activities resulted primarily from an increase in net loss of $62.8 million, excluding the $194.6 million of impairment charges, the $36.0 million MPOG acquisition gain and $51.4 million gains on sale of assets and business recorded in 2017; as well as an increase in the change in operating assets and liabilities of $18.0 million.

Investing Activities. For the year ended December 31, 2017, net cash used by investing activities was $40.5 million, a decrease of $205.2 million compared to the year ended December 31, 2016. The decrease of cash flows used by investing activities resulted primarily from the sale of our Propane Business of $160.0 million and lower net acquisitions/investments and additions of $57.6 million in 2017, partially offset by lower distributions from unconsolidated affiliates return of capital for $12.3 million.

Financing Activities. For the year ended December 31, 2017, net cash used by financing activities was $264.2 million, a decrease of $741.7 million compared to the year ended December 31, 2016. The decrease in cash flows from financing activities was due primarily to additional net pay downs on our Credit Agreement of $391.5, lower proceeds from our senior notes of $228.0 million, distributions to our General Partner due to our common control transactions for $86.3 million and the redemption of our Series D Units of $34.5 million, including distributed accrued PIK, partially offset by an increase of $44.3 million related to our General Partner's contributions.

Distribution to our unitholders

In accordance with our Partnership Agreement, after making distributions to holders of our outstanding preferred units, we make distributions to our common unitholders of record within 45 days following the end of each quarter provided that there is available cash for distribution. Generally, our available cash is (a) the sum of our i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and ii) cash on hand resulting from working capital borrowings made after the end of the quarter, (b) less the amount of any cash reserves established to i) provide for the proper conduct of the business and ii) comply with applicable law or loan or other contractual agreement to which we are part, including our Credit Agreement. Provided that there is available cash for distributions, such distributions are determined each quarter by the Board based on their consideration of our financial position, earnings, cash flow, current and future business needs, contractual restrictions and other relevant factors at that time. The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses for financial reporting purposes and may not make cash distributions during periods when we record net income for financial reporting purposes.

The minimum quarterly distribution, as defined in our partnership agreement, is $0.4125 per common unit per quarter, or $1.65 on an annualized basis. If, in any quarter, we distribute less than the minimum quarterly distribution on each common unit, then our common unitholders accumulate arrearages based on the number of initial public offering ("IPO") common units. We have 3.8 million IPO common units outstanding. The accumulated arrearages are equal to (a) the sum of the deficit between the quarterly distribution paid and the minimum quarterly distribution on all common units issued in our IPO (b) divided by the number of common units outstanding as of the end of such quarter. As we have more common units outstanding than were issued in the initial public offering, the arrearages associated with each common unit will be less than the deficit between the quarterly distribution paid on such common unit and the minimum quarterly distribution. Accumulated arrearages must be paid before any distribution will be made on our incentive distribution rights. As such, they give common unitholders a priority right to distributions, but, unlike arrearages on a debt instrument, do not create a liquidated payment obligation. At December 31, 2018, we had accumulated arrearages totaling $2.3 million.

As a result of the Second Amendment, we are not permitted to declare or make any cash distributions to our unitholders until our consolidated total leverage ratio is reduced to less than 5.00:1.00, as shown in the compliance certificate required to be delivered together with audited consolidated financial statements for the most recently completed fiscal year and unaudited consolidated financial statements for the most recently completed quarter. Therefore, the Credit Agreement prohibited us from making any cash distributions on our common units with respect to the fourth quarter of 2018, and we do not expect to make any distributions to on our common units with respect to the first quarter of 2019. We will not be permitted to make any cash distributions for future quarters until our consolidated total leverage ratio is reduced to less than 5.00:1.00.

We do not plan to pay distributions on any of our units through the completion of the Pending Merger.

If we were to pay distributions, DCF is an important non-GAAP supplemental measure used to compare basic cash flows generated by us in each period to the cash distributions paid to unitholders with respect to such period. The following displays our distribution coverage for the distributions paid with respect to the periods presented (in thousands):

72

	Years Ended December 31,		
	2018	2017	2016
Adjusted EBITDA	$184,614	$176,394	$177,565
Interest expense, net of capitalized interest	(82,410)	(66,465)	(21,433)
Amortization of deferred financing costs	7,485	5,117	3,236
Unrealized (loss) gain on interest rate swaps	1,154	(1,109)	(10,375)
Gain on extinguishment of debt	—	1,870	—
Letter of credit fees	21	517	—
Maintenance capital	(15,970)	(8,892)	(6,751)
Preferred unit distributions	(25,061)	(16,311)	(15,142)
Distributable cash flow	$69,833	$91,121	$127,100
Limited Partner distributions	$54,525	$89,378	$101,561
Distribution coverage	1.3x	1.0x	1.3x

Adjusted EBITDA and Distributable cash flow are non-GAAP measures. Please read Non-GAAP Financial Measures for more information and reconciliations to the most comparable GAAP measure.

During the year ended December 31, 2018, we paid a total of $54.5 million of distributions to our unitholders associated with the fourth quarter of 2017 and the first three quarters of 2018. This was made possible primarily by cash on hand plus distributions received relating to our unconsolidated affiliates and distribution support pursuant to our sponsor’s agreement to offset the shortfall in distributions from Delta House.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2018, our material off-balance sheet arrangements and transactions included operating lease arrangements and service contracts. There are no other transactions, arrangements or other relationships associated with our investments in unconsolidated affiliates or related parties that are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources. At December 31, 2018, our off-balance sheet arrangements totaled $160.4 million.

With respect to the quarters ended June 30, 2018 and September 30, 2018, pursuant to the terms of our Partnership Agreement, we have accumulated arrearages on our IPO common units of $2.3 million.

Capital Requirements

The energy business is capital intensive, requiring significant investment for the maintenance of existing assets and the acquisition
and development of new systems and facilities. We categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets) made to maintain our operating income or operating capacity; or

- expansion capital expenditures, incurred for acquisitions of capital assets or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our Partnership Agreement.

For the year ended December 31, 2018, capital expenditures totaled $96.6 million, including expansion capital expenditures of $79.2 million, maintenance capital expenditures of $16.0 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $1.4 million. For the year ended December 31, 2017, capital expenditures totaled $117.1 million, including expansion capital expenditures of $105.5 million, maintenance capital expenditures of $8.9 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $2.8 million. Of these capital expenditures amount for the year ended December 31, 2017, $3.1 million was incurred for the Propane Business that we disposed on September 1, 2017, as discussed in Item 8. Note 5. Dispositions of this 2018 Form 10-K.

Impact of Inflation on Operations

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2018, 2017 and 2016. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy, and we tend to experience inflationary pressure on the cost of our equipment, materials and supplies as increasing oil and natural gas prices also increase activity in our areas of operations.

Integrity Management

Certain operating assets require an ongoing integrity management program which is associated with high consequence areas ("HCA") that require on-going testing pursuant to the U.S. Department of Transportation regulations. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle, which varies from asset to asset and different segments within those asset areas and is date-stamped from the day the energized baseline is established for each operating asset. Our total program addresses approximately 112 HCA as of December 31, 2018. We expect to incur approximately $7.5 million in integrity management testing expenses during 2019. The amount may increase as our HCA mileage may increase through future acquisitions.

Contractual Obligations

The Partnership had the following non-cancelable contractual commitments as of December 31, 2018 (in thousands):

	Payments due by period						
Contractual Obligations	Total	Within Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
3.77% Senior Notes	$57,516	$2,233	$2,299	$4,430	$4,579	$4,733	$39,242
8.50% Senior Notes (1)	425,000	—	—	425,000	—	—	—
3.97% Secured Senior Notes	30,270	1,805	1,852	1,900	1,952	2,005	20,756
Revolving Credit Agreement	514,800	514,800	—	—	—	—	—
Interest payments on debt (2)	144,003	43,746	43,600	41,703	2,718	2,465	9,771
Operating lease obligations (3)	34,938	8,161	5,067	3,429	2,536	1,545	14,200
Asset retirement obligation (4)	71,297	3,846	—	—	—	—	67,451
Other (5)	125,495	2,795	2,828	2,686	2,404	2,441	112,341
Total	$1,403,319	$577,386	$55,646	$479,148	$14,189	$13,189	$263,761

(1) Upon closing of the JPE Merger, the proceeds from the 8.50% Senior Notes were used to repay the JPE Credit Agreement. On December 28, 2017, the Partnership issued an additional $125 million 8.50% Senior Notes, as discussed in Note 14. Debt Obligations.

(2) Excludes interest on our revolving credit agreement which had an outstanding balance of $514.8 million as of December 31, 2018 with a weighted average interest rate of 6.47%.

(3) Not including sublease income of $4.6 million.

(4)

In certain cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the ARO. In such cases, the ARO cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's experience or the asset's estimated economic life.

(5) Represents our commitment to certain long-term services contracts.

Impact of Seasonality

Results of operations in our Natural Gas Transportation Services segment are directly affected by seasonality due to higher demand for natural gas during the winter months, primarily driven by our LDC customers. On our AlaTenn system, we offer some customers seasonally-adjusted firm transportation rates that require customers to reserve capacity at rates that are higher in the period from October to March compared to other times of the year. On our Midla system, we offer customers seasonally-adjusted firm transportation reservation volumes that allow customers to reserve more capacity during the period from October to March compared to other times of the year. The combination of seasonally-adjusted rates and reservation volumes, as well as higher volumes overall, result in higher revenue and segment gross margin in our Natural Gas Transportation Services segment during the period from October to March compared to other times of the year. We generally do not experience seasonality in our Gas Gathering and Processing Services and Terminalling Servicing segments.

The volume of product that is handled, transported, throughput or stored in our refined products terminals is directly affected by the level of supply and demand in the wholesale markets served by our terminals. Overall supply of refined products in the wholesale markets is influenced by the absolute prices of the products, the availability of capacity on delivering pipelines and vessels, fluctuating refinery margins and the market’s perception of future product prices. Although demand for gasoline typically peaks during the summer driving season, which extends from April to September, and declines during the fall and winter months, most of the revenues generated at our refined products terminals do not experience any effects from such seasonality. However, the butane blending operations at our refined products terminals are affected by seasonality because of federal regulations governing seasonal gasoline vapor pressure specifications. Accordingly, we expect that the revenues we generate from butane blending will be highest in the winter months and lowest in the summer months.

Critical Accounting Policies and Estimates

The preparation of consolidated financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by our management to be critical to an understanding of the consolidated financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the consolidated financial statements for additional information about our critical accounting policies and estimates.

Use of Estimates. When preparing consolidated financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the consolidated financial statements. Estimates and assumptions are based on information available at the time such estimates and assumptions are made. Adjustments made with respect to the use of these estimates and assumptions often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of consolidated financial statements. Estimates and assumptions are used in, among other things, i) estimating unbilled revenues, product purchases and operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing long-lived assets, goodwill and intangible assets for possible impairment, iv) estimating the useful lives of assets and v) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Property, Plant and Equipment. We capitalize expenditures related to property, plant and equipment that have a useful life greater than one year. We also capitalize expenditures that improve or extend the useful life of an asset. Maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

We record property, plant, and equipment at cost and recognize depreciation expense on a straight-line basis over the related estimated useful lives of the assets which range from 3 to 40 years. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs.

We classify long-lived assets to be disposed of through sales that meet specific criteria as held for sale. We cease depreciating those assets effective on the date the asset is classified as held for sale. We record those assets at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, our estimate of fair value is re-determined when related events or circumstances change.

Impairment of Long Lived Assets. We evaluate the recoverability of our property, plant and equipment and intangible assets with definite lives when events or circumstances indicate we may not recover the carrying amount of the assets. We continually monitor our operations, business environment and the market to identify indicators that could suggest an asset or asset group may not be recoverable. We evaluate the asset or asset group for recoverability by estimating the undiscounted future cash flows expected to be derived from their use and disposition. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals and other factors. An asset or asset group is considered impaired when the estimated undiscounted cash flows are less than the carrying amount. In that event, an impairment loss is recognized to the extent that the carrying amount of the asset or asset group exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of fair values using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Operations.

Goodwill and Intangible Assets. We record goodwill for the excess of the cost of an acquisition over the fair value of the net assets of the acquired business. Goodwill is reviewed for impairment at least annually or more frequently if an event or change in circumstance indicates that an impairment may have occurred. We first assess qualitative factors to evaluate whether it is more likely than not that an impairment has occurred, and it is therefore necessary to perform the one-step goodwill impairment test. If the one-step goodwill impairment test indicates that the goodwill is impaired, an impairment loss is recorded, which is the difference between carrying value and fair value, with the impairment loss not to exceed the amount of goodwill recorded.

When performing a quantitative impairment test, we generally determine the fair value of our reporting units using a discounted cash flow method. In the event we enter into an agreement to sell all or substantially all of a reporting unit, we will utilize such information. While using the discounted cash flow method, we must make estimates of projected cash flows related to assets, which include, but are not limited to, assumptions about revenue growth rates, operating margins, weighted average costs of capital and future market conditions, the use or disposition of assets, estimated remaining life of assets, and future expenditures necessary to maintain current operations. We also must make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of energy commodities (such as natural gas, crude oil and refined products), our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other companies.

Under the discounted cash flow method, we determine fair value based on estimated future cash flows and EBITDA of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflects the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one-year budgeted amounts and five-year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur.

Cash flow estimates are based on the annual budget for the upcoming year and forecasted amounts for multiple subsequent years. The annual budget process is typically completed near the annual goodwill impairment testing date, and management uses the most recent information for the annual impairment tests. The forecast is also subjected to a comprehensive update annually in conjunction with the annual budget process and is revised periodically to reflect new information and revised expectations.

The estimates of future cash flows and EBITDA are subjective in nature and are subject to impacts from the business risks described in Part I. Item 1A. Risk Factors of this 2018 Form 10-K. While we believe we have made reasonable estimates and assumptions based on available information to calculate the fair value, if future results are not consistent with our estimates, changes in fair value estimates could result in additional impairments in future periods that could be material to our results of operations.

We record the estimated fair value of acquired customer contracts, relationships and dedicated acreage agreements as intangible assets. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging between 5 years and 30 years. We assess intangible assets for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

As of December 31, 2018, we had approximately $51.7 million of goodwill in our Consolidated Balance Sheet within three reporting units. Of this amount, approximately $35.7 million of goodwill in our Silver Dollar reporting unit in the Liquid Pipelines and Services segment was at risk of failing the one-step quantitative test. Our quantitative analysis of Silver Dollar resulted in the fair value exceeding the carrying value by approximately $23.8 million, or 13%, and therefore no impairment was recorded.

Investment in Unconsolidated Affiliates. We hold membership interests in entities that own and operate natural gas pipeline systems and NGL and crude oil pipelines in and around Louisiana, Alabama, Mississippi and the Gulf of Mexico. While we have significant influence over these entities, we do not control them and therefore, they are accounted for using the equity method and are reported in Investment in unconsolidated affiliates in the Consolidated Balance Sheets. We evaluate the recoverability of these investments on a regular basis and recognize impairment write downs if we determine a loss in value represents an other than temporary decline.

Asset Retirement Obligations. AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and operation. An ARO is initially measured at its estimated fair value. Upon initial recognition, we also record an increase to the carrying amount of the related long-lived asset. We depreciate the asset using the straight-line method over the period during which it is expected to provide benefits. After initial recognition, we revise the ARO to reflect the passage of time and for changes in the estimated amount or timing of cash flows.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for certain of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's experience or the asset's estimated economic life. The useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the ARO. Indeterminate ARO costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

Revenue Recognition. Our revenue is derived from the provision of gathering, processing, transportation, terminalling and storage services and the sale of commodities primarily to marketers and brokers, refiners and chemical manufacturers, utilities and power generation customers, industrial users and local distribution companies. Beginning on January 1, 2018, we account for revenue from contracts with customers in accordance with Topic 606. The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided at a point in time or over a period of time. Topic 606 requires that a contract’s 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 to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied. See Item 8. Note 2. Recent Accounting Pronouncements of the 2018 Form 10-K for further discussion regarding our January 1, 2018 implementation of the new Revenue Recognition guidance.

Price Risk Management Activities. We have structured our hedging activities in order to minimize our commodity pricing and interest rate risks and to help maintain compliance with certain financial covenants in our credit agreement. These hedging activities rely upon forecasts of our expected operations and financial structure. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecast transactions and the level of hedging activity executed.

We use mark-to-market accounting for our commodity hedges and interest rate swaps. We record monthly realized gains and losses on hedge instruments based upon cash settlements information. The settlement amounts vary due to the volatility in the commodity market prices throughout each month. We also record unrealized gains and losses for the net change in the mark-to-market valuation of the hedges.

Recent Accounting Pronouncements.

For information regarding new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements, refer to Item 8. Note 2. Recent Accounting Pronouncements of this 2018 Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to certain market risks that are inherent in our financial instruments and arise from changes in commodity prices and interest rates. A discussion of our market risk exposure in financial instruments is presented below.

Commodity Price Risk

Overview

We are exposed to the impact of market fluctuations in the prices of natural gas, crude oil, NGLs and condensate. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Natural gas, crude oil and NGL prices are impacted by changes in the supply and demand for these energy commodities, as well as market uncertainty. For a discussion of the volatility of natural gas, crude oil, and NGL prices, see Part I. Item 1A. Risk Factors of this 2018 Form 10-K. Adverse effects on our cash flow from reductions in natural gas, crude oil and NGL prices could adversely affect our operating cash flows and our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, optimization of our assets and the use of derivative contracts. Our overall direct exposure to movements in natural gas prices is minimal as a result of natural hedges inherent in our current contract portfolio. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing.

To minimize the effect of commodity prices and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price downturns while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the Board. Historically, the commodity derivatives are in the form of swaps and collars.

We enter into commodity contracts with counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions.

Commodity Price Risk per Segment

Gas Gathering and Processing segment. We purchase and take title to a portion of the NGLs that we sell, which may expose us to changes in the price of NGLs in our sales markets. We manage this commodity price risk by limiting our net open positions and through the concurrent purchase and sale of like quantities of NGLs that are intended to lock in positive margins based on the timing, location or quality of the crude oil purchased and delivered.

Liquid Pipelines and Services segment. We purchase and take title to a portion of the crude oil that we sell, which may expose us to changes in the price of crude oil in our sales markets. We manage this commodity price risk by limiting our net open positions and through the concurrent purchase and sale of like quantities of crude oil that are intended to lock in positive margins based on the timing, location or quality of the crude oil purchased and delivered.

Natural Gas Transportation Services and Offshore Pipelines and Services segments. We do not take title to the products we transport and therefore have no direct commodity price exposure.

During 2018, we entered into several commodity contracts with financial counterparties to hedge our 2018 exposure to commodity prices, which were settled in December 2018 and were set to expire in January 2019. Due to our overall low commodity exposure relative to fee-based and fixed-margin contract portfolio, management seeks to opportunistically enter into commodity contracts to hedge our natural gas, NGL and crude oil exposure.

We entered into short term contracts in 2018 to hedge crude oil and NGL exposure, of which most had settled as of December 31, 2018. We also have entered into contracts to hedge a portion of our NGL and crude oil exposure in 2019.

As of December 31, 2018, we have not been required to post collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

Sensitivity analysis - The table below summarizes our commodity-related financial derivative instruments and fair values, as well as the effect on fair value of an assumed hypothetical 10% change in the underlying price of the commodity (in thousands).

Commodity Swaps	Fair Value Asset (Liability)	Effect of 10% Price Increase	Effect of 10% Price Decrease
NGLs Fixed Price (gallons)	$(2)	$(259)	$26

Interest Rate Risk

Overview

Our revolving credit facility bears interest at a variable rate and exposes us to interest rate risk. From time to time, we may use certain derivative instruments to hedge our exposure to variable interest rates. For the year ended December 31, 2018, we had exposure to changes in interest rates on our indebtedness associated with our Credit Agreement. To manage the impact of the interest rate risk associated with our Credit Agreement, we enter into interest rate swaps from time to time, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows. We do not hold or purchase financial instruments or derivative financial instruments for trading purposes.

As of December 31, 2018, we had a combined notional principal amount of $550.0 million of variable to fixed interest rate swap agreements. As of December 31, 2018, the maximum length of time over which we have hedged a portion of our exposure due to interest rate risk is through December 31, 2022.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the report of our independent registered public accounting firm, begin on page F-1 of this 2018 Form 10-K.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file, or submit, under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms, and that such information is accumulated and communicated to the management of our General Partner, including our General Partner’s principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision of the principal executive officer and principal financial officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act). Based on our evaluation, our principal executive officer and principal financial officer concluded that the Partnership’s disclosure controls and procedures were not effective as of December 31, 2018 as a result of the material weaknesses in our internal control over financial reporting described below.

Despite the material weaknesses, our principal executive officer and principal financial officer have concluded that the consolidated financial statements included in this report fairly present in all material respects our financial condition, results of operations and cash flows for the periods presented.

Inherent Limitations of Internal Controls

Our management does not expect that our disclosure controls and procedures will prevent or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been prevented or detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Management monitors the Partnership's disclosure controls and procedures and makes modifications, as necessary, with the intent that the disclosure controls and procedures will be adequately designed and operating effectively to prevent or detect material misstatements to its consolidated financial statements and to deter fraud.

Management's Annual Report on Internal Control over Financial Reporting

Management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)). The Partnership's internal control over financial reporting was designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles.

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.

Management, under the supervision of the principal executive officer and principal financial officer of our General Partner, assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment identified material weaknesses in our internal control over financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Partnership's annual or interim consolidated financial statements will not be prevented or detected on a timely basis. As a result of these material weaknesses, management concluded that our internal control over financial reporting was not effective as of December 31, 2018.

Management identified the following control deficiencies that constituted material weaknesses in our internal control over financial reporting as of December 31, 2018:

We did not maintain an effective control environment as we lacked sufficient oversight of activities related to our internal control over financial reporting and had an insufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with our financial reporting requirements. This material weakness contributed to additional material weaknesses, as the Partnership did not design and maintain effective controls over: verifying that complex, non-routine transactions were recorded appropriately, which such control deficiency resulted in out-of-period adjustments recorded to the income statement in the fourth quarter of 2016 and a revision to the 2015 balance sheet and cash flows; all financial statement assertions of revenue and receivables, specifically the review of the accounting for certain contracts, the review that price, volume and other key contractual terms used to record revenue are consistent with the terms of arrangement and the review that revenue is recorded in the proper period, which such control deficiency resulted in immaterial adjustments to the 2017 and 2018 consolidated financial statements; all financial statement assertions related to acquisitions and divestitures, specifically verifying the existence, rights and obligations associated with assets acquired and liabilities assumed, reviewing the valuation of the purchase price allocation and reviewing the completeness and accuracy of related disclosures, which such control deficiency resulted in immaterial adjustments to the 2017 consolidated financial statements; the period-end financial reporting process, specifically verifying the review of journal entries are performed by individuals separate from the preparer and that the journal entries are complete, accurate and property supported, and the review of account reconciliations and financial statement analysis to support all financial statement assertions of the consolidated financial statements and disclosures, which such control deficiency resulted in immaterial adjustments to the 2017 and 2018 consolidated financial statements; and the accuracy and valuation of AROs, goodwill, other intangible assets and finite-lived assets, specifically the review of the model, data, assumptions and calculations used in determining the estimated asset retirement obligation and in impairment tests, and the related identification of changes in events and circumstances that indicate it is more likely than not that an impairment indicator has occurred, which such control deficiency resulted in adjustments to the accounting for AROs and impairments in goodwill, other intangible assets and finite-lived assets for the year ended 2017.

Additionally, these material weaknesses could result in a misstatement of substantially all of the financial statement accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

Additionally, we did not maintain effective controls over certain information technology ("IT") general controls for applications used in the preparation of our consolidated financial statements. Specifically, we did not maintain user access controls to ensure appropriate segregation of duties and that adequately restrict user and privileged access to the financial application, programs and data to appropriate Partnership personnel. These IT deficiencies did not result in a material misstatement to the consolidated financial statements, however, the deficiencies, when aggregated, could impact our ability to maintain effective segregation of duties, as well as maintain effective IT-dependent controls (such as automated controls that address the risk of a material misstatement to one or more assertions, along with the IT controls and underlying data that support the effectiveness of system-generated data and reports), which could result in misstatements of substantially all of the financial statement accounts and disclosures, resulting in a material misstatement to the annual or interim consolidated financial statements that otherwise would not be prevented or detected.

PricewaterhouseCoopers LLP, our independent registered public accounting firm that audited the consolidated financial statements included in this 2018 Form 10-K, also audited the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2018, as stated in their report included on page F-1 of this 2018 Form 10-K.

Material Weakness Remediation

Management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weaknesses identified herein. Specifically, we are taking numerous steps that we believe will address the underlying causes of the material weaknesses, primarily through hiring of additional personnel with expertise in technical accounting, financial reporting and internal controls, enhancing our training and education programs, strengthening our controls documentation and internal review procedures, setting guidelines for documentation of review controls, engaging consultants with technical expertise in accounting, updating accounting policies and procedures to improve the overall effectiveness of internal control over financial reporting, and implementing and integrating adequate information technology systems.

Since the end of 2016, under the oversight of our Audit Committee, we have been, and continue to be, actively engaged in the design and implementation of remedial measures to address the material weaknesses in our internal control over financial reporting, and management is committed to remediating the material weaknesses. While plans have been made to enhance our internal control over financial reporting relating to the material weaknesses, management is still in the process of implementing and testing these processes and procedures and additional time is required to complete implementation and to assess and ensure the sustainability of these procedures. Management believes these actions will strengthen our internal control over financial reporting and be effective in remediating the material weaknesses described above. Management is committed to continuous improvement of the Partnership's internal control processes and will continue to devote significant time and attention to these remediation efforts. However, the material weaknesses cannot be considered remediated until the applicable remediated controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

Changes in internal control over financial reporting

As disclosed under Material Weakness Remediation, we have continued the process of remediating our material weaknesses. There have been no changes in internal control over financial reporting that occurred during the three months ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our principal executive officer and principal financial officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this 2018 Form 10-K as Exhibits 31.1 and 31.2. The certifications of our principal executive officer and principal financial officer pursuant to 18 U.S.C. 1350 are furnished with this 2018 Form 10-K as Exhibits 32.1 and 32.2.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We do not have directors or officers, which is commonly the case with publicly traded partnerships. We are managed by the directors and executive officers of our General Partner. Our General Partner is not elected by our unitholders and will not be subject to re-election in the future. HPIP and AMID GP Holdings, a wholly owned subsidiary of Magnolia, own all of the membership interests in our General Partner. Our unitholders are not entitled to elect the directors of our General Partner or directly or indirectly participate in our management or operations. Our General Partner owes certain contractual duties to our unitholders. Our General Partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend for any indebtedness incurred to be nonrecourse to our General Partner.

Our Partnership Agreement provides for the Board to designate a Conflicts Committee to review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. The members of the Conflicts Committee may not be executive officers or employees of our General Partner or directors, executive officers or employees of its affiliates. Messrs. Fasullo, Kendall and Tywoniuk serve as members of the Conflicts Committee, with Mr. Tywoniuk serving as chairman. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us and not a breach by our General Partner of any duties it may owe us or our unitholders. In addition, the Board has an Audit Committee (the "Audit Committee"), which complies with the NYSE requirements and oversees risk management activities, as well as a Compensation Committee (the "Compensation Committee").

Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a listed limited partnership like us to have a majority of independent directors on the Board.

Our General Partner has adopted a Code of Business Conduct and Ethics (the "Code of Ethics"), that applies to the directors, officers and employees of our General Partner. If our General Partner amends the Code of Ethics or grants a waiver, including an implicit waiver, of the Code of Ethics, we will, if required under SEC rules, disclose the information on our website at www.americanmidstream.com. Our General Partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

All of the senior officers of our General Partner devote a sufficient portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our business; however, they may also devote a portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our General Partner, which has separate ongoing business operations.

The non-management members of the Board meet in executive sessions without management participation at least quarterly. These directors do not constitute a committee of the Board and therefore do not take action at such sessions, although the participating directors may make recommendations for consideration by the full Board.

Interested parties may communicate directly with a director, or group of directors, in the manner prescribed by our Corporate Governance Guidelines.

We make available free of charge, within the "Investor Relations—Corporate Governance" section of our website at http://www.americanmidstream.com, and in print to any unitholder who so requests, the Code of Ethics and our

Corporate Governance Guidelines. Unitholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Secretary of our General Partner at: American Midstream GP, LLC, 2103 CityWest Boulevard, Building #4, Suite 800, Houston, Texas 77042. The information contained on, or connected to, our website is not incorporated by reference into this 2018 Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

The Board determined that Peter A. Fasullo, Donald R. Kendall Jr. and Gerald A. Tywoniuk all met the NYSE's independence requirements. Messrs. Fasullo, Kendall and Tywoniuk serve as the members of the Audit Committee, with Mr. Tywoniuk serving as chairman. Each member of the Audit Committee is independent as such term is defined in Rule 10A-3(b)(1) under the Exchange Act and under the NYSE listing standards applicable to audit committees. Our General Partner is generally required to have at least three independent directors serving on the Board at all times. The Board has determined that Mr. Tywoniuk is a financial expert as defined by the NYSE and the Exchange Act. Messrs. Bourdon and Erhard serve as members of the Compensation Committee, with Mr. Erhard serving as chairman.

A copy of the Audit Committee charter is available on our website at www.americanmidstream.com/investor-relations.

Currently, Mr. Erhard presides at the executive sessions of the non-management directors and Mr. Tywoniuk presides at the executive sessions of the independent directors.

Directors are appointed for a term of one year and 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 and are subject to the terms of their employment agreements, if applicable. The following table shows information for the executive officers and directors of our General Partner as of March 22, 2019:

Name	Age	Position with American Midstream GP, LLC
Lynn L. Bourdon III	57	Chairman of the Board, President and Chief Executive Officer
Eric T. Kalamaras	45	Senior Vice President and Chief Financial Officer
Rene L. Casadaban	50	Senior Vice President and Chief Operating Officer
Christopher B. Dial	42	Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary
Louis J. Dorey	63	Senior Vice President - Business Development
Karen S. Acree	62	Vice President and Chief Accounting Officer
Edward E. Greene	56	Vice President - Gathering, Processing, and Terminals
Ryan K. Rupe	44	Vice President - Natural Gas Services and Offshore Pipelines
Stephen W. Bergstrom	61	Director and Executive Strategy Advisor
John F. Erhard	44	Director
Donald R. Kendall Jr.	66	Director
Daniel R. Revers	57	Director
Peter A. Fasullo	66	Director
Joseph W. Sutton	71	Director
Lucius H. Taylor	44	Director
Gerald A. Tywoniuk	57	Director

Executive Officers

Lynn L. Bourdon III was appointed Chairman, President and Chief Executive Officer in December 2015. Previously, Mr. Bourdon served as President and Chief Executive Officer of Enable Midstream Partners, LP ("Enable Midstream"). Prior to Enable Midstream, he served as Group Senior Vice President of NGL & Natural Gas Marketing, Petrochemical, Refined Products & Marine at Enterprise Products Partners, LP ("Enterprise Products"). Mr. Bourdon joined Enterprise Products as Senior Vice President of NGL Supply & Marketing in 2003 and served in various senior management positions during his tenure. Prior to his employment at Enterprise Products, Mr. Bourdon served as Senior Vice President and Chief Commercial Officer for Orion Refining Corporation. He also held leadership positions at En*Vantage, PG&E Corporation and Valero and earlier served in various capacities at the Dow Chemical Company. Mr. Bourdon serves as a member of the Energy Advisory Board with the University of Houston, and as a member of the Gas Processing Association and has served on the Propane Education and Research Advisory Council (PERC). Mr. Bourdon received a Bachelor of Science degree in mechanical engineering from Texas Tech University, and a Master of Business Administration from the University of Houston and is a member of Tau Beta Pi and Pi Tau Sigma.

Eric T. Kalamaras was appointed Senior Vice President and Chief Financial Officer in July 2016. Previously, Mr. Kalamaras served as Executive Vice President and Chief Financial Officer of several energy midstream and infrastructure companies where, as the principal financial officer, he led strategic planning and mergers and acquisitions and completed over $15 billion of transactions. Mr. Kalamaras served as Chief Financial Officer at Valerus Energy Holdings, Delphi Midstream Partners and Atlas Pipeline Partners, LP ("Atlas Pipeline"). At Atlas Pipeline Mr. Kalamaras led its $2.5 billion financial restructuring. Prior to Atlas Pipeline, he spent a combined 10 years at Wells Fargo and Banc of America Securities providing investment banking and capital markets services to clients in the energy and natural resource industries. Mr. Kalamaras holds a Bachelor of Science in Business Administration from Central Michigan University and a Master of Business Administration from Wake Forest University.

Rene L. Casadaban was appointed Senior Vice President and Chief Operating Officer in March 2017. Mr. Casadaban has 27 years of midstream project management and business development experience for onshore, offshore and deepwater pipeline systems.

Mr. Casadaban is the former Chief Operating Officer for Summit Midstream Partners, LP (“Summit”). Prior to joining Summit, Mr. Casadaban worked for Enterprise Products as the Director for Deepwater Business Development of floating production platforms and offshore pipelines. Mr. Casadaban has also served as an independent consultant to ExxonMobil Corporation and GulfTerra Energy Partners, LP for Gulf of Mexico and international pipeline projects. Prior to such roles, Mr. Casabadan was employed at At Land and Marine Engineering Limited, and was responsible for managing domestic and international pipeline river crossings and beach approaches by horizontal directional drilling. Mr. Casadaban began his career as a Field Engineer for McDermott International Inc. He currently serves on the board of directors of Angel Reach and holds a Bachelor of Science in Building Construction from Auburn University.

Christopher B. Dial has served as our Senior Vice President, General Counsel and Chief Compliance Officer of our General Partner since January 2018. Prior to his appointment with our General Partner, Mr. Dial served as General Counsel of Susser Holdings II, LP. after spending over eight years in a number of roles, most recently as Associate General Counsel and Corporate Secretary, with both Susser Holdings Corporation and Sunoco, LP. Mr. Dial began his career as an Associate Attorney for Andrews Kurth, LLP, where he represented clients on a variety of corporate, capital markets and other transactional matters. Mr. Dial holds a Bachelor of Arts in Economics from Southwestern University and a Juris Doctor from the University of Houston Law Center.

Louis J. Dorey has served as Senior Vice President of Business Development since January 2014. Mr. Dorey previously served in various capacities at Continuum Energy Services from 2005 to 2014, being responsible for strategic planning, mergers and acquisitions, corporate business development and capital markets activities, and also served as interim CFO. Mr. Dorey was employed by Dynegy Inc. from 1997 to 2002, where he held various positions including Vice President of Strategy and Planning for Power Assets Group, President of Retail and Wholesale Marketing and Interim CFO. From 1991 to 1997, Mr. Dorey served as Vice President of Mergers and Acquisitions of Destec Energy Inc. and completed various acquisitions, including leading the sale of Destec Energy Inc. to Dynegy Inc. Mr. Dorey has participated in over $5 billion of transactions (including mergers, acquisitions and development transactions), managed five regional wholesale marketing offices and a national retail marketing group, and participated in the closing and integration of three public mergers. Mr. Dorey earned a Bachelor of Business Administration from the University of Oklahoma and a Juris Doctorate from the University of Texas, Austin.

Karen S. Acree was appointed as Vice President and Chief Accounting Officer in April 2018. Ms. Acree has over 35 years of extensive knowledge in accounting, financial reporting and tax through her leadership with multiple publicly traded energy companies. Ms. Acree is the former Chief Accounting Officer for Jones Energy, Inc. ("Jones"). Prior to joining Jones, Ms. Acree was the Vice President, Controller and Chief Accounting Officer of W&T Offshore, Inc. Ms. Acree holds a Bachelor of Business Administration in Accounting from Texas Tech University and is a Certified Public Accountant in the State of Texas.

Edward E. Greene was appointed as Vice President - Gathering, Processing and Terminals as of the closing of the merger with JPE on March 8, 2017. Mr. Greene joined American Midstream in March 2016 as Vice President, Onshore Gathering and Processing and NGL Liquids Marketing. Prior to joining American Midstream, he led the NGL and crude businesses of Enable Midstream. Prior to Enable Midstream, he served in a number of commercial leadership roles for Enterprise Products, including Vice President of Refined Products and Vice President of Unregulated NGL Assets. Mr. Greene joined Enterprise Products after over 20 years with the Dow Chemical Company, where he served in various capacities in commercial management, R&D and sales and marketing. He received a Bachelor of Science in Chemical Engineering from the Georgia Institute of Technology.

Ryan K. Rupe was appointed as Vice President - Natural Gas Services and Offshore Pipelines as of the closing of the merger with JPE on March 8, 2017. Previously, Mr. Rupe served as our Vice President of Natural Gas Services and Offshore Pipelines and as our Vice President of Commercial Operations. Prior to his appointment as an officer of

American Midstream, he was a partner and served as Director of Commercial Operations for High Point Energy, LLC ("High Point Energy"). Mr. Rupe joined High Point Energy from CIMA Energy, where he was an owner and served as Director of Gulf Coast Trading and Gas Scheduling. Mr. Rupe is a graduate of Texas A&M University and is a member of the Texas A&M Athletic Hall of Fame and Major League Baseball Players Alumni Association.

Directors

Stephen W. Bergstrom was elected as a member of the Board in April 2013, Mr. Bergstrom was appointed as President and Chief Executive Officer of our General Partner in May 2013 and served in such positions until retiring from such positions in December 2015. Mr. Bergstrom also currently serves as a director on the board of directors of The Williams Companies (NYSE: WMB) Mr. Bergstrom remains a member of the Board. In June 2017, we employed Mr. Bergstrom, on a part time basis, as our Executive Strategy Advisor. Mr. Bergstrom was appointed to the Board in connection with his affiliation with ArcLight, which controls our General Partner, and due to his breadth of experience in the energy industry. Mr. Bergstrom acted as an exclusive consultant to ArcLight from 2002 to 2015, assisting ArcLight in connection with its energy investments. Prior to his consultancy with ArcLight, Mr. Bergstrom worked from 1986 to 2002 for Natural Gas Clearinghouse, which became Dynegy, Inc. ("Dynegy"). Mr. Bergstrom acted in various capacities at Dynegy, ultimately serving as its President and Chief Operating Officer. Prior to his time at Dynegy, Mr. Bergstrom acted as a gas supply representative for Northern Natural Gas from 1981 to 1986. Mr. Bergstrom began his career at Transco from 1980 to 1981. Mr. Bergstrom earned a Bachelor of Science from Iowa State University in 1979. We believe that Mr. Bergstrom's breadth of experience in the energy industry provide him with the necessary skills to be a member of the Board.

John F. Erhard was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Erhard, a partner at ArcLight, joined ArcLight in 2001 and has 17 years of energy finance and private equity experience. Mr. Erhard earned a Bachelor of Arts in Economics from Princeton University and a Juris Doctor from Harvard Law School. Mr. Erhard previously served on the board of directors of Patriot Coal. In addition, Mr. Erhard has experience in the MLP sector having served on the board of directors of Buckeye Partners (NYSE: BPL) and its publicly traded general partner, Buckeye GP Holdings. We believe that Mr. Erhard's 17 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Donald R. Kendall, Jr. was elected as a member of the Board in July 2013. Mr. Kendall serves as an independent director and as a member of the Audit Committee. Mr. Kendall is currently Managing Director and Chief Executive Officer of Kenmont Capital Partners, LP, an investment management firm based in Houston specializing in alternative investments and private equity. Previously, Mr. Kendall was a Portfolio Manager for Carlson Capital, L.P., President of Cogen Technologies Capital Company, L.P., Chairman and Chief Executive Officer of Palmetto Partners, Ltd. and a Managing Director in the project finance and leasing group at Credit Suisse First Boston. He serves as a director of Tangent Energy Solutions and SkyCentrics and he also served as a director and audit committee chairperson of SolarCity (and chair of the Special Committee) and Stream Energy. Mr. Kendall also currently serves as a director of the board of directors and a member of the audit committee of Talos Energy (NYSE: TALO). In addition, Mr. Kendall serves in various capacities at not-for-profit organizations, including The Jane Goodall Institute, The Houston Zoo Conservation Committee, Mar Alliance, Bat Conservation International and Earthwatch International. He also is on the Board of Overseers of the Amos Tuck School of Business Administration at Dartmouth College. Mr. Kendall received a Bachelor of Arts degree from Hamilton College and a Master of Business Administration with high honors from The Amos Tuck School of Business Administration. He was a Tuck Scholar and a recipient of the W. M. Bollenbach, Jr. Fellowship. We believe that Mr. Kendall's investment experience and general business knowledge qualifies him to be a member of the Board. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

Daniel R. Revers was elected as a member of the board of directors in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Revers is Managing Partner and co-founder of ArcLight and has 26 years of energy finance and private equity experience. Mr. Revers manages the ArcLight office and is responsible for overall investment, asset management, strategic planning and operations of ArcLight and its funds. Prior to forming ArcLight in 2000, Mr. Revers was a Managing Director in the Corporate Finance Group at John

Hancock Financial Services, where he was responsible for the origination, execution and management of a $6 billion portfolio consisting of debt, equity and mezzanine investments in the energy industry. Mr. Revers serves in various capacities for a number of not-for-profit organizations, including currently serving on the Board of Overseers at the Amos Tuck School of Business Administration and the Board of Trustees of The Rivers School. Mr. Revers earned a Bachelor of Arts in Economics from Lafayette College and a Master of Business Administration from the Amos Tuck School of Business Administration at Dartmouth College. We believe that Mr. Revers' 26 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Peter A. Fasullo was elected as a member of the Board in June 2016. Mr. Fasullo serves as an independent director and as a member of the Audit Committee. Mr. Fasullo has 40 years of experience in the midstream and refining industries and currently serves as a Principal of En*Vantage, Inc. In March 1999, Mr. Fasullo co-founded En*Vantage, Inc., an energy investment and strategic management consulting firm that provides advisory services to energy and financial companies, having advised more than 300 clients in the energy and financial industries. In March 2016, En*Vantage was cited by Morgan Stanley as a leading energy consultancy. Prior to forming En*Vantage, Mr. Fasullo was with Valero Energy in various executive management positions in their midstream and refining businesses from 1983 to 1997. Shortly thereafter, Mr. Fasullo was hired to lead MAPCO Inc.'s corporate and business development department and helped merge MAPCO into the Williams Companies in 1998. From 1976 to

1980, Mr. Fasullo was a process engineer with M.W. Kellogg and from 1980 to 1983, he was a market consultant with PACE Consultants and Engineers advising midstream and refining companies. Mr. Fasullo earned a Bachelor of Arts and a Master of Chemical Engineering degree from Rice University and a Master of Business Administration from the University of Houston.

Joseph W. Sutton was elected as a member of the Board in May 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Sutton also currently serves as a director of the board of directors of Ameresco (NYSE: AMRC). Mr. Sutton is a founder of High Point Energy a precursor company to the Partnership. Mr. Sutton is the founder and owner of Sutton Ventures Group, LLC, an energy investment firm. One of his early successes was as a founder of Millennium Midstream, which was later purchased by Eagle Rock. In 2007, he founded and has since led Consolidated Asset Management Services, or CAMS, which provides asset management, operations and maintenance, information technology, budgeting, contract management and development services to power plant ventures, oil and gas companies, renewable energy companies and other energy businesses. From 1992 to November 2000, Mr. Sutton worked for Enron Corporation, an energy company, where he most recently served as vice chairman and as chief executive officer of Enron International. We believe that Mr. Sutton's over 20 years of energy and financial experience provide him with the necessary skills to be a member of the Board.

Lucius H. Taylor was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Taylor joined ArcLight in 2007. He has 17 years of experience in energy finance, private equity and engineering. Prior to joining ArcLight, Mr. Taylor was a Vice President in the Energy and Natural Resource Group at FBR Capital Markets where he focused on raising public and private capital for companies in the power and energy sectors. Mr. Taylor began his career as a geologist at CH2M HILL, Inc., a global engineering, construction and operations firm. Mr. Taylor earned a Bachelor of Arts in Geology from Colorado College, a Master of Science in Hydrogeology from the University of Nevada and a Master of Business Administration from the Wharton School at the University of Pennsylvania. In addition, Mr. Taylor has experience in the MLP sector and currently serves on the board of directors of the general partner of TransMontaigne Partners, L.P. (NYSE: TLP). We believe that Mr. Taylor's 17 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Gerald A. Tywoniuk was elected as a member of the Board in May 2011. From May 2010 to the present, Mr. Tywoniuk has provided interim and project CFO services. He also currently serves as a director on the board of directors of the general partner of Westmoreland Resource Partners, LP (OTC PINK:WMLPQ) ("Westmoreland") and serves as a director and audit committee member on the board of directors of the general partner of Landmark Infrastructure Partners LP (NASDAQ:LMRK). In February 2018, Mr. Tywoniuk was appointed Chairman of Westmoreland, and in March 2019, he was appointed Acting CEO and Acting Secretary of Westmoreland. Westmoreland, which is in the coal mining industry, filed for Chapter 11 protection in October 2018. Mr. Tywoniuk holds a Bachelor of Commerce degree from The University of Alberta, Canada, and is a Canadian Chartered Professional Accountant (Chartered Accountant). Mr. Tywoniuk has more than 36 years of experience in accounting and finance, including service as a member of the board of directors of four public companies, Chief Financial Officer of three public companies, and Vice President/Controller of another public company. Mr. Tywoniuk's extensive accounting, financial and executive management experience, and his prior experience with publicly traded partnerships, provide him with the necessary skills to be a member of the Board and a member and the chairman of the Audit Committee. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

Family Relationships

There are no family relationships among any of the Partnership's or our General Partner's directors and executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the Board members and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10% unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they file with the SEC.

Based solely on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during the year ended December 31, 2018, all filing requirements applicable to our officers, directors and greater than 10% beneficial owners were met in a timely manner, except Messrs. Bourdon, Casadaban, Dial, Dorey, Greene, Kalamaras, McCrary and Rupe each filed one late Form 4 regarding the granting of phantom units. Additionally, Messrs. Dorey and Rupe each filed two late Form 4’s regarding the vesting and conversion of phantom units to common units.

Item 11. Executive Compensation

Our General Partner, under the direction of the Board is responsible for managing our operations and employs all of the employees that operate our business. The compensation payable to our General Partner's officers is paid by our General Partner and such payments are reimbursed by us on a dollar-for-dollar basis. Our unitholders are not entitled to vote on executive compensation.

The following is a discussion of the compensation policies and decisions of the Compensation Committee, with respect to the following individuals, who are executive officers of our General Partner and referred to as the "named executive officers" for the fiscal year ended December 31, 2018:

Name	Position with American Midstream GP, LLC
Lynn L. Bourdon III	Chairman of the Board, President, and Chief Executive Officer
Eric T. Kalamaras	Senior Vice President and Chief Financial Officer
Rene L. Casadaban	Senior Vice President and Chief Operating Officer
Louis J. Dorey	Senior Vice President - Business Development
Christopher B. Dial	Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary

Our compensation program is designed to recognize key managers who are critical to our profitability and growth. We utilize compensation to attract and retain management talent and to motivate key employees to focus consistently on growth and value creation. In addition, our compensation program aligns incentives for management and unitholders, focusing on long-term value creation rather than short-term gain.

This section should be read together with the compensation tables that follow, which disclose the compensation awarded to, earned by, or paid to, the named executive officers with respect to the three years ended December 31, 2018.

Role of the Board, the Compensation Committee and Management

The Board has appointed the Compensation Committee to assist the Board in discharging its responsibilities relating to compensation matters, including matters relating to compensation programs for directors and executive officers of the General Partner. The Compensation Committee has overall responsibility for evaluating, recommending and in certain circumstances approving our compensation plans, policies and programs, determining the compensation and benefits of executive officers, and granting awards under and administering our equity compensation plans. Our Chief Executive Officer provides periodic recommendations to the Compensation Committee regarding the performance and compensation of the other named executive officers as well as the amount allocated to the short term incentive plan and LTIP compensation pools. The Compensation Committee is charged with, among other things, establishing compensation practices and programs that are (i) designed to attract, retain and motivate exceptional leaders, (ii) structured to align compensation with our overall performance, (iii) implemented to promote achievement of short-term and long-term business objectives consistent with our strategic plans, and (iv) applied to reward performance.

As described in further detail below under Elements of the Compensation Programs, the compensation program for our executive officers consists of base salaries, annual incentive bonuses, and long-term cash and equity awards, including awards under the American Midstream GP, LLC, Long-Term Incentive Plan, which we refer to as our LTIP, currently in the form of equity-based phantom units, as well as other customary employment benefits such as a 401(k) plan, and health and welfare benefits. We expect that total compensation of our executive officers and the components of compensation and allocation among components of their annual compensation will be reviewed on at least an annual basis by the Compensation Committee. Management, on behalf of the Compensation Committee, engaged the services of Longnecker & Associates ("Longnecker"), a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for the executive officers for 2018. The Compensation Committee has considered factors relevant to Longneckers's independence from management under SEC and NYSE rules and has determined the firm is independent from management. The Longnecker study was based on compensation for a group of peer companies with similar operations obtained from public documents as well as multiple survey sources, including the 2017 Longnecker & Associates Midstream Industry Compensation Survey, 2017 Mercer General and

Executive Benchmark and others from Towers Watson, Kenexa and more.

In arriving at recommendations for 2018 executive compensation, the Compensation Committee considered a number of factors, including the 2018 Longnecker study, the subjective criteria described under the caption Compensation Objectives and Methodology below, and the recommendations of our Chief Executive Officer with respect to other executive officers and key employees. Following the Compensation Committee's determinations and recommendations, base salary levels, 2017 bonus payouts, target bonus amounts for 2018 and 2018 LTIP awards for our executive officers were approved by our board.

Compensation Discussion and Analysis

87

Compensation Objectives and Methodology

The principal objective of our executive compensation program is to attract and retain individuals of demonstrated competence, experience and leadership who share our business aspirations, values, ethics and culture. A further objective is to provide incentives to and reward our executive officers and other key employees for positive contributions to our business and operations, and to align their interests with our unitholders' interests.

In setting our compensation programs, we consider the following objectives:

- to create unitholder value through sustainable earnings and cash available for distribution;
- to provide a significant percentage of total compensation that is "at-risk" or variable;
- to encourage significant equity holdings to align the interests of executive officers and other key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation and executive compensation.

Taking account of the foregoing objectives, we structure total compensation for our executives to provide a guaranteed amount of cash compensation in the form of base salaries, while also providing a meaningful amount of annual cash compensation that is at risk and dependent on our performance and individual performance of the executives, in the form of discretionary annual bonuses. We also seek to provide a portion of total compensation in the form of equity-based awards under our LTIP in order to align the interests of executives and other key employees with those of our unitholders and for retention purposes.

Compensation decisions for individual executive officers are the result of the subjective analysis of a number of factors, including the individual executive officer's experience, skills or tenure with us and changes to the individual executive officer's position. In evaluating the contributions of executive officers and our performance, although no predetermined numerical goals were established, a variety of financial measures have been generally considered, including non-GAAP financial measures used by management to assess our financial performance, such as Adjusted EBITDA and distributable cash flow. For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use Adjusted EBITDA to evaluate our operating performance, see Part II. Item 7. MD&A – How We Evaluate Our Operations of this 2018 Form 10-K. In addition, a variety of factors related to the individual performance of the executive officer are taken into consideration.

We do not believe that our compensation policies and practices create risks that are reasonably likely to have a material adverse effect on the Partnership. We believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees). Short-term annual incentives are generally paid pursuant to discretionary bonuses enabling the CEO and Compensation Committee to assess the actual behavior of our employees as it relates to risk taking in awarding a bonus. Our use of equity based long-term compensation serves our compensation program's goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk taking.

In making individual compensation decisions, the Compensation Committee historically has not relied on pre-determined performance goals or targets. Instead, determinations regarding compensation have resulted from the exercise of judgment based on all reasonably available information and, to that extent, were discretionary. The amount of each executive officer's current compensation will be considered as a base against which determinations are made as to whether increases are appropriate to retain the executive officer in light of competition or in order to provide continuing performance incentives. Subject to the provisions contained in the executive officer's employment agreement, if any, the Compensation Committee has discretion to adjust any of the components of compensation to achieve our goal of recruiting, promoting and retaining executive officers and key individuals with the skills necessary to execute our business strategy and develop, grow and manage our business.

The Compensation Committee has also utilized benchmarking compensation levels across a range of peer group companies operating in the midstream market that we compete with for talent to help inform specific award levels for named executive officers and key managers. Going forward, we expect that the Compensation Committee will make compensation decisions taking into account trends occurring within our industry, including from a peer group of companies, which we expect will include, but not be limited to, the following similar publicly traded partnerships: Archrock Partners, L.P., Crestwood Equity Partners LP, DCP Midstream Partners LP, DCP Midstream LP, Delek US Holdings, Inc., Enable Midstream Partners LP, Genesis Energy L.P., Global Partners LP, Holly Energy Partners, L.P., NGL Energy Partners LP, Noble Midstream Partners LP, SemGroup Corporation, Summit Midstream Partners LP, Tallgrass Energy Partners, LP and USA Compression Partners, LP.

Elements of the Compensation Programs

Overall, the executive officer compensation programs are designed to be consistent with the philosophy and objectives set forth above. The principal elements of our executive officer compensation programs are summarized in the table below, followed by a more detailed discussion of each compensation element.

Element	Characteristics	Purpose
Base Salaries	Fixed annual cash compensation.	Keep our annual compensation competitive with the defined market for skills and experience necessary to execute our business strategy.
Annual Incentive Bonuses	Performance-related discretionary annual cash incentives earned based on our objectives and individual performance of the executive officers.	Align performance with objectives that drive our business and reward executive officers for achieving yearly performance objectives and for their individual contributions to these objectives during the fiscal year.
Equity-Based Awards (Phantom-Units and Distribution Equivalent Rights)	Long-term, equity-based awards granted at the discretion of the Compensation Committee. Grants typically consist of phantom units that vest ratably over four years and may be settled upon vesting with either a net cash payment or an issuance of common units, at the discretion of the Board. Distribution Equivalent Rights, or DERs, and options have been granted on a limited basis.	Align interests of executive officers with unitholders and motivate and reward executive officers to increase unitholder value over the long term. Ratable vesting over a four-year period is designed to facilitate retention of executive officers.
Cash Retention Awards	Long-term cash-based awards, subject to vesting provisions typically resembling those governing time-based equity awards.	Retain key employees by providing a long-term incentive for continued employment without the volatility or dilutive impact of equity-based awards during periods of price instability.
Retirement Plan	Qualified retirement plan benefits are available for our executive officers and all other regular full-time employees through our 401(k) plan.	Provide our executive officers and other employees with the opportunity to save for their future retirement.
Health and Welfare Benefits	Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for our executive officers and all other regular full-time employees.	Provide benefits to meet the health and wellness needs of our executive officers, other employees and their families.

Base Salaries

Base salaries for our executive officers will be determined annually by an assessment of our overall financial and operating performance, each executive officer's performance evaluation and changes in executive officer responsibilities. While many aspects of performance can be measured in financial terms, senior management will also be evaluated in areas of performance that are more subjective. These areas include development and execution of strategic plans, leading the development of management and other employees, innovation and improvement in our business activities and each executive officer's involvement in industry groups and in the communities that we serve. We seek to compensate executive officers for their performance throughout the year with annual base salaries that are fair and competitive within our marketplace. We believe that executive officer base salaries should be competitive with salaries for executive officers in similar positions and with similar responsibilities in our marketplace and adjusted for financial and operating performance and each executive officer's performance evaluation, length of service with us and previous work experience. Individual salaries have historically been established by the Board, upon the recommendation of the Compensation Committee, based on the general industry knowledge and experience of its members, in alignment with these considerations, to ensure the attraction, development and retention of superior talent. Going forward, we expect that salary decisions will continue to focus on the above considerations and will also take into account relevant market data, including the market data and peer group data.

We review base salaries annually to ensure continuing consistency with market levels and our level of financial performance during the previous year. Future adjustments to base salaries and salary ranges will reflect movement in the competitive market as well as individual performance. Annual base salary adjustments, if any, for the Chief Executive Officer will be determined by the Board upon the recommendation of the Compensation Committee. Annual base salary adjustments, if any, for the other executive officers will be determined by the Board upon the recommendation of the Compensation Committee, taking into account input from the Chief Executive Officer.

Our board approved the following base salaries for our named executive officers effective April 1, 2018:

Name	Base Salary at the end of 2018
Lynn L. Bourdon III	$600,000
Eric T. Kalamaras	345,000
Rene L Casadaban	345,000
Louis J. Dorey	290,000
Christopher B. Dial	285,000

Annual Incentive Bonuses

Executive officers are rewarded for their contribution to our financial and operational success through the award of discretionary annual cash incentive bonuses. Annual cash incentive awards, if any, for the Chief Executive Officer are determined by the Board upon the recommendation of the Compensation Committee. Annual cash incentive awards, if any, for the other executive officers are determined by the Board upon the recommendation of the Compensation Committee taking into account input from the Chief Executive Officer.

We review cash bonus awards for the named executive officers annually to determine award payments for prior fiscal year performance, as well as to establish target bonus amounts for the current fiscal year. At the beginning of each year, the Compensation Committee meets with the Chief Executive Officer to discuss Partnership and individual goals for the year and what each executive is expected to contribute in order to help the Partnership achieve those goals. However, the amounts of the annual bonuses have been and are determined at the discretion of the Board upon the recommendation of the Compensation Committee with input from the Chief Executive Officer.

While target bonuses for our executive officers have been initially set at dollar amounts that are between 75% to 100% of their base salaries, the Compensation Committee has had broad discretion to retain, reduce or increase the award amounts when making its final bonus recommendations. Bonuses (similar to other elements of the compensation provided to executive officers) historically have not been solely based on a prescribed formula, predetermined goals or specified performance targets but rather have been determined on a discretionary basis and generally have been based on a subjective evaluation of individual, company-wide and industry performances. Target bonus amounts for 2018 for all of the executive officers are set forth in the table below.

The Board and the Compensation Committee believe that this approach to assessing performance results in a more comprehensive evaluation for compensation decisions. In 2018, the Compensation Committee recognized the following factors in making discretionary annual bonus recommendations and determinations:

- a subjective company performance evaluation based on company-wide financial performance including actual EBITDA versus budgeted EBITDA to assess company performance and adjusted as needed for new acquisitions and major capital expenditure programs in 2018;
- a subjective individual performance evaluation for executive officers and other factors deemed relevant; and
- the scope, level of expertise and experience required for the executive officer's position.

These factors were selected as the most appropriate measures upon which to base the annual incentive cash bonus decisions because our Compensation Committee believes that they help align individual compensation with performance and contribution. With respect to its evaluation of company-wide financial performance, although no predetermined numerical goals were established, the Compensation Committee generally reviewed our results with respect to Adjusted EBITDA as compared to operating budget and cash available for distribution in making annual bonus determinations.

Following its performance assessment and based on our financial performance with respect to these criteria and the Compensation Committee's qualitative assessment of individual performance, the Board upon the recommendation of the Compensation Committee, determined to award the incentive bonus amounts, which were paid in cash, set forth in the table below to our named executive officers for performance in 2018.

Name	2018 Target Bonus	2018 Bonus Earned
Lynn L. Bourdon III	$600,000	$500,000
Eric T. Kalamaras	310,500	260,000
Rene L. Casadaban	310,500	310,000
Louis J. Dorey	217,500	203,000
Christopher B. Dial	213,750	235,000

For 2018, the Compensation Committee determined base annual incentive compensation award recommendations on additional company-wide criteria as well as industry criteria, recognizing the following factors as part of its determination of annual incentive bonuses (without assigning any particular weight to any factor):

- financial performance for the prior fiscal year, including Adjusted EBITDA and distributable cash flow;
- distribution performance for the prior fiscal year;
- unitholder total return for the prior fiscal year; and
- competitive compensation data of executive officers.

These factors were selected as the most appropriate measures upon which to base the annual cash incentive bonus decisions going forward because the Compensation Committee believes that they will most directly correlate to increases in long-term value for our unitholders.

Equity-Based Awards

Design. The LTIP was adopted in November 2009 in connection with our formation and was most recently amended and restated in 2016. In adopting the LTIP, the Board recognized that it needed a source of equity to attract new members to and retain members of the management team, as well as to provide an equity incentive to other key employees and non-employee directors. We believe the LTIP promotes a long-term focus on results and aligns executive and unitholder interests.

The LTIP is designed to encourage responsible and profitable growth while taking into account non-routine factors that may be integral to our success. Long-term incentive compensation in the form of equity grants (e.g. phantom units, unit options, and PSUs (see below)) are used to provide incentives for performance that leads to enhanced unitholder value, encourage retention and closely align the executive officers' interests with unitholders' interests. Equity grants provide a vital link between the long-term results achieved for our unitholders and the rewards provided to executive officers and other key employees.

Phantom Units. A phantom unit is a notional unit granted under the LTIP that entitles the holder to receive an amount of cash equal to the fair market value of one common unit upon vesting of the phantom unit, unless the Board elects to pay such vested phantom unit with a common unit in lieu of cash. Unless an individual award agreement provides otherwise, the LTIP provides that unvested phantom units are forfeited at the time the holder terminates employment or Board membership, as applicable. The terms of the award agreements of our named executive officers provide that a termination due to death or long-term disability results in full acceleration of vesting. In general, phantom units awarded under our LTIP vest as to 25% of the award on each of the first four anniversaries of the date of grant.

Unit Options. A unit option is a right to purchase a common unit at the fair market value per common unit on the date of grant. The Compensation Committee has utilized unit option grants in special circumstances associated with the new hire or promotion of a named executive officer, and each award has unique vesting terms.

Performance Based Awards. In November 2017, the Board approved the grant of performance based awards ("PSUs") to create a highly accretive, long-term retention tool to key personnel whom management expects to drive performance over the long-term. The PSUs will vest on November 20, 2022, subject to acceleration in certain circumstances.

Distribution Equivalency Rights ("DER"). In April 2018, the Board approved a one time annual LTIP grant for all executives, other than Mr. Bourdon, that would be eligible to receive DER payments on unvested units in the amount of 50% of the quarterly distributions paid to common unitholders. The DER payments on unvested units, which is a practice of some peer group MLP organizations, were approved so that the executives' long-term incentive awards were closer in value to the existing unitholders' units. Our 75% reduction in our distribution on our common units announced in July 2018 resulted in a commensurate reduction in DER payments to holders of DER's, and, following the full suspension of our common unit distribution in January 2019, no DER payments will be made until, and unless, we resume our distribution on common units.

Equity-Based Award Policies. The LTIP is administered by the Compensation Committee. The Compensation Committee, at its discretion, may elect to settle each vested phantom unit with a common unit at the date of vesting in lieu of cash.

All Other Compensation

Long-Term Cash Retention Program. In August 2018, in recognition of challenges in retaining key personnel resulting from factors including the significant drop and volatility in the price of our common units and the termination of the SXE Merger Agreement and the Contribution Agreement, our Board approved a special long-term cash retention award applicable to all employees holding unvested time-based phantom units in an amount of $6 per phantom unit. This program was approved in order to help preserve the retention incentives associated with long-term equity awards that had experienced significant declines in value without the dilutive impact and volatility associated with equity-based awards. These long-term cash awards are generally subject to acceleration under the same circumstances as the phantom units to which they relate, except that these awards will automatically vest upon an involuntary termination of the award recipient (unless such termination is for cause or due to performance deficiencies) following certain changes in control, including certain going private transactions. Performance based awards, unit options, and any subsequent awards were specifically excluding from this program.

Deferred Compensation. Tax-qualified retirement plans are a common way that companies assist employees in preparing for retirement. We provide our eligible executive officers and other employees with an opportunity to save for their retirement by participating in our 401(k) plan. The 401(k) plan allows our executive officers and other employees to defer compensation (up to IRS imposed limits) for retirement and permits us to make annual discretionary matching contributions to the plan. For 2018, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 6% of the employee's eligible compensation. Decisions regarding this element of compensation do not impact any other element of compensation.

Other Benefits. Each of the named executive officers is eligible to participate in our employee benefit plans which provide for medical, dental, vision, disability insurance and life insurance benefits, which are provided on the same terms as available generally to all salaried employees.

Recoupment Policy. We currently do not have a recoupment policy applicable to annual incentive bonuses or equity awards. The Compensation Committee expects to continue to evaluate the need to adopt such a policy in 2019, in light of current legislative policies as well as economic and market conditions.

Employment, Change in Control and Severance Arrangements. The Board and the Compensation Committee consider the maintenance of a sound management team to be essential to protecting and enhancing our best interests. To that end, we recognize that the uncertainty that may exist among management with respect to their "at-will" employment with our General Partner may result in the departure or distraction of management personnel is to our detriment. Accordingly, our General Partner has agreed to an arrangement for Mr. Bourdon that we believe is appropriate to encourage his continued attention and dedication. Mr. Bourdon's severance arrangement is described more fully below under Employment Agreements with Named Executive Officers.

Summary Compensation Table for the Three Years ended December 31, 2018
The following table sets forth certain information with respect to the compensation paid to the named executive officers for the three years ended December 31, 2018.

	Year	Salary	Bonus	Stock Awards [1]	All Other Compensation	Total Compensation
Lynn L. Bourdon III [2]	2018	$575,000	$500,000	$947,223	$ 1,478,700	$ 3,500,923
Chairman of the Board, President and Chief Executive Officer	2017	500,000	500,000	1,105,049	16,154	2,121,203
	2016	500,000	750,000	598,812	15,838	1,864,650
Eric T. Kalamaras [3]	2018	335,000	260,000	373,200	29,604	997,804
Senior Vice President and Chief Financial Officer	2017	300,000	290,000	1,285,341	73,658	1,948,999
	2016	137,019	92,000	359,730	240,189	828,938
Rene L. Casadaban [4]	2018	335,000	310,000	373,200	30,916	1,049,116
Senior Vice President and Chief Operating Officer	2017	227,577	275,000	1,526,890	8,681	2,038,148
	2016	—	—	—	—	—
Louis J. Dorey [5]	2018	286,250	203,000	224,329	22,323	735,902
Senior Vice President - Business Development	2017	275,000	230,000	920,267	14,644	1,439,911
	2016	275,000	200,000	22,271	13,892	511,163
Christopher B. Dial [6]	2018	268,558	235,000	449,300	48,906	1,001,764
Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary	2017	—	—	—	—	—
	2016	—	—	—	—	—

93

(1) These amounts reflect the aggregate grant date value of each phantom unit award, unit options award granted, and the performance unit awards in each of the three years ended December 31, 2018 calculated in accordance with FASB ASC Topic 718. In general, employees are not entitled to distributions declared on the underlying unit while the phantom unit is unvested; therefore, the grant date fair value of the phantom units is calculated by reducing the grant date price, by the present value of the distributions expected to be paid on the underlying units during the requisite service period. See the table below for these calculations. For additional information on the assumptions used to calculate the grant date fair value of equity incentive awards, refer to Part II. Item 8. Note 18 – Long-Term Incentive Plan of this 2018 Form 10-K, incorporated herein by reference.

	2018 Phantom Unit Awards		
	Grant date value of phantom units before distributions(7)	Present value of distributions	Grant date value of phantom units less distributions
Lynn L. Bourdon III	$1,500,000	$552,777	$947,223
Eric T. Kalamaras	$457,500	$84,300	$373,200
Rene L. Casadaban	$457,500	$84,300	$373,200
Louis J Dorey	$275,000	$50,671	$224,329
Christopher B. Dial	$530,800	$81,500	$449,300

(2) Other compensation includes $1,200,000 for a cash retention award payment, $18,000 of 401(k) Savings Plan and HSA employer matching contributions and $260,700 in DER associated with Mr. Bourdon's December 2015 grant.

(3) Other compensation includes $16,500 of 401(k) Savings Plan employer matching contributions and $13,014 in DER associated with Mr. Kalamaras' April 2018 grant.

(4) Other compensation includes $17,811 of 401(k) Savings Plan and HSA employer matching contributions and $13,014 in DER associated with Mr. Casadaban's April 2018 grant.

(5) Other compensation includes $14,446 of 401(k) Savings Plan and HSA employer matching contributions and $7,877 in DER associated with Mr. Dorey's April 2018 grant.

(6) Other compensation includes $16,494 of 401(k) Savings Plan and HSA employer matching contributions, $23,750 in relocation assistance and $8,662 in DER associated with Mr. Dial's January 2018 grant.

(7) The number of phantom units granted on April 2, 2018 was calculated based on a market value of $10.80 per common unit.

Grants of Plan-Based Awards for 2018

Name	Grant Date	Target ($)	Target (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Grant Date Fair Value of Stock and Option Awards (1)
Lynn L. Bourdon III					
Phantom Units	4/02/18	—	138,889	138,889	$947,223
Cash Retention Award	8/31/18	$1,684,014	—	—	—
Eric T. Kalamaras					
Phantom Units	4/02/18	—	42,361	42,361	373,200
Cash Retention Award	8/31/18	623,712	—	—	—
Rene L. Casadaban					
Phantom Units	4/02/18	—	42,361	42,361	373,200
Cash Retention Award	8/31/18	460,302	—	—	—
Louis J. Dorey					
Phantom Units	4/02/18	—	25,463	25,463	224,329
Cash Retention Award	8/31/18	398,184	—	—	—
Christopher B. Dial					
Phantom Units (2)	1/29/18	—	—	28,000	361,200
Phantom Units	4/02/18	—	—	10,000	88,100
Cash Retention Award	8/31/18	228,000	—	—	—

(1) Amounts shown in this column do not reflect dollar amounts actually received by our named executive officers. Instead, these amounts reflect the aggregate grant date value. For additional information on the assumptions used to calculate the grant date fair value of equity incentive awards, refer to Part II. Item 8. Note 18 - Incentive Compensation of this 2018 Form 10-K, which is incorporated herein by reference.

(2) The phantom units awarded to Mr. Dial in conjunction with the start of his employment were made eligible for a 50% DER payment starting during the second quarter of 2018.

Employment Agreements with Named Executive Officers ("NEO")

Our General Partner has entered into an employment agreement with Lynn L. Bourdon III. The employment agreement with Mr. Bourdon has an initial term of three years, through January 2, 2019, after which it will be automatically extended for successive one-year terms until either party elects to terminate the agreement by providing written notice at least 60 days prior to the end of the expiration of the initial or extended term, as applicable. The base salary and target bonus amounts set forth in Mr. Bourdon’s employment agreement is discussed above and the employment agreement provides that the base salary may be increased but not decreased. Mr. Bourdon’s employment agreement also provides that he may also be eligible to receive awards under the LTIP as determined by the Compensation Committee.

Mr. Bourdon’s employment agreement contains certain confidentiality covenants prohibiting him from, among other things, disclosing confidential information relating to our General Partner or any of its affiliates, including us. The employment agreement also contains non-competition and non-solicitation restrictions, which apply during the term of Mr. Bourdon’s employment with our General Partner and, with certain exceptions, continue for a period of 6 to 12 months following termination for any reason.

Mr. Bourdon’s employment agreement also provides for, among other things, the payment of severance benefits under certain circumstances. See Potential Payment Upon Termination or Change in Control - Employment Agreements and Severance Agreements with Named Executive Officers below for a description of these benefits under the agreements.

Outstanding Equity-Based Awards at December 31, 2018

The following table provides information regarding outstanding equity-based awards held by the named executive officers as of December 31, 2018. All such equity-based awards consist of phantom units, performance units and unit options granted under the LTIP.

	Option Awards				Stock Awards	
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#) [1] [2]	Market Value of Shares or Units of Stock That Have Not Vested ($) [3]
Lynn L. Bourdon III [4]	—	200,000	$ 7.50	03/15/20	280,669	$ 850,427
Eric T. Kalamaras [5]	—	30,000	$ 7.50	07/31/20	183,952	557,375
Rene L. Casadaban [6]	3,750	11,250	$ 14.85	04/03/27	145,467	440,765
Louis J. Dorey	—	—	—	—	66,364	201,083
Christopher B. Dial	—	—	—		38,000	115,140

96

(1) Ownership in the phantom unit awards is subject to forfeiture until the vesting date. The LTIP is administered by the Compensation Committee, which at its discretion, may elect to settle such vested phantom units with common units in lieu of cash. Although our General Partner has the option to settle vested phantom units in cash, our General Partner has not historically settled these awards in cash. Under the LTIP, phantom units typically vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment.

(2) The following table shows the dates on which the awards in the outstanding equity awards table vest and the corresponding number of units (subject to the acceleration provisions upon certain termination of the holder's employment as described under Potential Payments Upon Termination or Change in Control below.

Vesting Date	Lynn L. Bourdon III	Eric T. Kalamaras	Rene L. Casadaban	Louis J. Dorey	Christopher B. Dial
1/29/19	—	—	—	—	7,000
2/23/19	—	—	—	3,498	—
2/26/19	66,022	—	—	12,104	—
4/1/19	59,974	17,787	22,042	10,763	5,000
7/26/19	—	40,000	—	—	—
1/29/20	—	—	—	—	7,000
2/26/20	—	—	—	12,104	—
4/1/20	59,975	17,787	22,042	10,764	5,000
1/29/21	—	—	—	—	7,000
4/1/21	59,975	17,787	22,042	10,765	—
1/29/22	—	—	—	—	7,000
4/1/22	34,723	10,591	10,591	6,366	—
11/20/22		80,000	80,000	60,000	—
Total	280,669	183,952	156,717	126,364	38,000

(3) The market value of phantom units that had not vested as of December 31, 2018 was calculated based on the fair market value of our common units as of December 31, 2018, which was $3.03 multiplied by the number of unvested phantom units. See Part II. Item 7. MD&A - Critical Accounting Policies and Estimates Equity-Based Awards of this 2018 Form 10-K.

(4) In conjunction with the execution of Mr. Bourdon’s employment agreement effective December 10, 2015, the Board approved a grant of 200,000 phantom units of the Partnership. The phantom units contain DERs based on the extent to which the Partnership's Series A Preferred Unitholders receive distributions in cash. The grant will vest on January 1, 2019, subject to acceleration in certain circumstances and will expire on March 15, 2020.

(5) Effective August 2016, the Board approved the grant of an option to purchase 30,000 common units. The grant will vest on July 31, 2019, subject to continued employment, and will expire on July

31, 2020.

(6) In April 2017, the Board approved the grant of an option to purchase 15,000 common units of the Partnership at an exercise price per unit equal to $14.85. The options will vest over four years at a rate of 25% per year. The options expire on April 3, 2027, or ten years from the date of grant.

Option Exercises and Stock Vested in 2018

The following table shows the phantom unit awards that vested during 2018.

Name	Option Awards: Number of Shares Acquired on Exercise (#)	Option Awards: Value Realized on Exercise ($)	Stock Awards: Number of Units Acquired on Vesting (#)	Stock Awards: Value Realized on Vesting ($) (1)
Lynn L. Bourdon III	—	—	291,273	$ 1,985,884
Eric T. Kalamaras	—	—		