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

Form 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended March 31, 2019

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: 001-35172

NGL Energy Partners LP
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**27-3427920**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
6120 South Yale Avenue, Suite 805 **Tulsa, Oklahoma**	**74136**
(Address of Principal Executive Offices)	(Zip Code)

(918) 481-1119
(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Trading Symbols	Name of Each Exchange on Which Registered
Common units representing Limited Partner Interests	NGL	New York Stock Exchange
Fixed-to-floating rate cumulative redeemable perpetual preferred units	NGL-PB	New York Stock Exchange
Fixed-to-floating rate cumulative redeemable perpetual preferred units	NGL-PC	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. Yesx No o

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

The aggregate market value at September 30, 2018 of the Common Units held by non-affiliates of the registrant, based on the reported closing price of the Common Units on the New York Stock Exchange on such date ($11.60 per Common Unit) was $1.0 billion. For purposes of this computation, all executive officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates.

At May 28, 2019, there were 125,966,868 common units issued and outstanding.

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Forward-Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Certain words in this Annual Report such as "anticipate," "believe," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "plan," "project," "will," and similar expressions and statements regarding our plans and objectives for future operations, identify forward-looking statements. Although we and our general partner believe such forward-looking statements are reasonable, neither we nor our general partner can assure they will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected. Among the key risk factors that may affect our consolidated financial position and results of operations are:

- the prices of crude oil, natural gas liquids, gasoline, diesel, ethanol, and biodiesel;
- energy prices generally;
- the general level of crude oil, natural gas, and natural gas liquids production;
- the general level of demand, and the availability of supply, for crude oil, natural gas liquids, gasoline, diesel, ethanol, and biodiesel;
- the level of crude oil and natural gas drilling and production in areas where we have water treatment and disposal facilities;
- the price of gasoline relative to the price of corn, which affects the price of ethanol;
- the ability to obtain adequate supplies of products if an interruption in supply or transportation occurs and the availability of capacity to transport products to market areas;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of foreign oil and gas producing nations;
- the effect of weather conditions on supply and demand for crude oil, natural gas liquids, gasoline, diesel, ethanol, and biodiesel;
- the effect of natural disasters, lightning strikes, or other significant weather events;
- the availability of local, intrastate, and interstate transportation infrastructure with respect to our truck, railcar, and barge transportation services;
- the availability, price, and marketing of competing fuels;
- the effect of energy conservation efforts on product demand;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- the effect of legislative and regulatory actions on hydraulic fracturing, wastewater disposal, and the treatment of flowback and produced water;
- hazards or operating risks related to transporting and distributing petroleum products that may not be fully covered by insurance;
- the maturity of the crude oil, natural gas liquids, and refined products industries and competition from other marketers;
- loss of key personnel;
- the ability to renew contracts with key customers;
- the ability to maintain or increase the margins we realize for our terminal, barging, trucking, wastewater disposal, recycling, and discharge services;
- the ability to renew leases for our leased equipment and storage facilities;
- the nonpayment or nonperformance by our counterparties;
- the availability and cost of capital and our ability to access certain capital sources;

- a deterioration of the credit and capital markets;
- the ability to successfully identify and complete accretive acquisitions, and integrate acquired assets and businesses;
- changes in the volume of hydrocarbons recovered during the wastewater treatment process;
- changes in the financial condition and results of operations of entities in which we own noncontrolling equity interests;
- changes in applicable laws and regulations, including tax, environmental, transportation, and employment regulations, or new interpretations by regulatory agencies concerning such laws and regulations and the effect of such laws and regulations (now existing or in the future) on our business operations;
- the costs and effects of legal and administrative proceedings;
- any reduction or the elimination of the federal Renewable Fuel Standard;
- changes in the jurisdictional characteristics of, or the applicable regulatory policies with respect to, our pipeline assets; and
- other risks and uncertainties, including those discussed under Part I, Item 1A–"Risk Factors."

You should not put undue reliance on any forward-looking statements. All forward-looking statements speak only as of the date of this Annual Report. Except as may be required by state and federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events, or otherwise. When considering forward-looking statements, please review the risks discussed under Part I, Item 1A–"Risk Factors."

PART I

References in this Annual Report to (i) "NGL Energy Partners LP," the "Partnership," "we," "our," "us," or similar terms refer to NGL Energy Partners LP and its operating subsidiaries, (ii) "NGL Energy Holdings LLC" or "general partner" refers to NGL Energy Holdings LLC, our general partner, (iii) "NGL Energy Operating LLC" refers to NGL Energy Operating LLC, the direct operating subsidiary of NGL Energy Partners LP, (iv) the "NGL Energy GP Investor Group" refers to, collectively, the 44 individuals and entities that own all of the outstanding membership interests in our general partner, and (v) the "NGL Energy LP Investor Group" refers to, collectively, the 15 individuals and entities that owned all of our outstanding common units before the closing date of our initial public offering.

We have presented operational data in Part I, Item 1–"Business" for the year ended March 31, 2019. Unless otherwise indicated, this data is as of March 31, 2019.

Item 1. Business

Overview

We are a Delaware limited partnership formed in September 2010. At March 31, 2019, our operations included:

- Our Crude Oil Logistics segment purchases crude oil from producers and marketers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets.
- Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services and sells freshwater to producers for exploration and production activities.
- Our Liquids segment supplies natural gas liquids to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada using its leased underground storage and fleet of leased railcars, markets regionally through its 27 owned terminals throughout the United States, and provides terminaling and storage services at its salt dome storage facility joint venture in Utah.
- Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations , purchases refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedules them for delivery at various locations throughout the country. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties.

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG ("DCC"). On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior Plus Corp. ("Superior") and on August 14, 2018, we sold our previously held interest in Victory Propane, LLC ("Victory Propane"). These transactions represent a strategic shift in our operations and will have a significant effect on our operations and financial results going forward. Accordingly, the results of operations and cash flows related to our former Retail Propane segment (including equity in earnings of Victory Propane) have been classified as discontinued operations for all periods presented and prior periods have been retrospectively adjusted in the consolidated statements of operations and consolidated statements of cash flows. In addition, the assets and liabilities related to our former Retail Propane segment have been classified as held for sale within our March 31, 2018 consolidated balance sheet. See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion of the transaction.

For more information regarding our reportable segments, see Note 12 to our consolidated financial statements included in this Annual Report.

Acquisitions

The following summarizes our acquisitions over the past five fiscal years.

Year Ended March 31, 2015

- In July 2014, we acquired TransMontaigne Inc. (“TransMontaigne”). The operations of TransMontaigne included the marketing of refined products. As part of this transaction, we also purchased inventory from the previous owner of TransMontaigne, the 2% general partner interest, the incentive distribution rights, a 19.7% limited partner interest in TransMontaigne Partners L.P. (“TLP”), and assumed certain terminaling service agreements with TLP from an affiliate of the previous owner of TransMontaigne. See “Dispositions” below for a discussion of the sale of the general and limited partner interests in TLP.
- In November 2014, we acquired two saltwater disposal facilities in the Bakken shale play in North Dakota. See “ Dispositions” below for a discussion of the sale of our Bakken saltwater disposal business.
- In February 2015, we acquired Sawtooth Caverns, LLC (“Sawtooth”), which owns a natural gas liquids salt dome storage facility in Utah with rail and truck access to western United States markets and entered into a construction agreement to expand the storage capacity of the facility. See “Dispositions” below for a discussion of the joint venture of our Sawtooth business.
- During the year ended March 31, 2015, we acquired 16 water treatment and disposal facilities under a previous development agreement.
- During the year ended March 31, 2015, we acquired eight retail propane businesses. See “Dispositions” below for a discussion of the sale of our Retail Propane segment.

Year Ended March 31, 2016

- In August 2015, we acquired four saltwater disposal facilities and a 50% interest in an additional saltwater disposal facility in the Delaware Basin portion of the Permian Basin in West Texas. See “Dispositions” below for a discussion of the sale of our South Pecos water disposal business.
- In January 2016, we acquired a 57.125% interest in NGL Water Pipelines, LLC operating in the Delaware Basin portion of the Permian Basin in West Texas.
- During the year ended March 31, 2016, we acquired 15 water treatment and disposal facilities under a previous development agreement.
- During the year ended March 31, 2016, we acquired six retail propane businesses. See “Dispositions” below for a discussion of the sale of our Retail Propane segment.

Year Ended March 31, 2017

- In June 2016, we acquired an additional 24.5% interest in NGL Water Pipelines, LLC operating in the Delaware Basin portion of the Permian Basin in West Texas.
- In June 2016, we acquired the remaining 65% ownership interest in Grassland Water Solutions, LLC (“Grassland”). See “Dispositions” below for a discussion of the sale of Grassland.
- In September 2016, we acquired the remaining 25% ownership interest in three water solutions facilities in the Eagle Ford shale play in Texas.
- In January 2017, we acquired a natural gas liquids terminal that supports refined products blending in Port Hudson, Louisiana, and a natural gas liquids and condensate facility in Kingfisher, Oklahoma.
- During the year ended March 31, 2017, we acquired three water treatment and disposal facilities.
- During the year ended March 31, 2017, we acquired four retail propane businesses. See “Dispositions” below for a discussion of the sale of our Retail Propane segment.

Year Ended March 31, 2018

- During the year ended March 31, 2018, we acquired the remaining 50% ownership interest in NGL Solids Solutions, LLC.

- During the year ended March 31, 2018, we acquired seven retail propane businesses and certain assets from Victory Propane. See “Dispositions” below for a discussion of the sale of our Retail Propane segment.

Year Ended March 31, 2019

- On April 24, 2018, we acquired the remaining 18.375% interest in NGL Water Pipelines, LLC operating in the Delaware Basin portion of the Permian Basin in West Texas.
- During the three months ended June 30, 2018, we acquired three retail propane businesses. See “Dispositions” below for a discussion of the sale of our Retail Propane segment.
- In January 2019, we acquired two refined products terminals located in Georgia.
- In March 2019, we acquired a natural gas liquids terminal business that consisted of five propane rail terminals, located in the Eastern United States, a 50% ownership interest in an additional rail terminal, located in the state of Maine, and an import/export terminal located in Chesapeake, Virginia, with the capability to load and unload ships ranging in size from handy-sized vessels up to very large gas carriers.
- During the year ended March 31, 2019, we acquired six saltwater disposal facilities (including 22 saltwater disposal wells), two ranches and four freshwater facilities (including 45 freshwater wells).

Year Ending March 31, 2020

See Note 19 to our consolidated financial statements included in this Annual Report for a discussion of the acquisitions that occurred subsequent to March 31, 2019.

Dispositions

Year Ended March 31, 2016

Sale of General Partner Interest in TLP

On February 1, 2016, we sold our general partner interest in TLP to an affiliate of ArcLight Capital Partners (“ArcLight”) for net proceeds of $343.1 million. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. As discussed further below, TLP is no longer an equity method investment. As part of this transaction, we retained TransMontaigne Product Services LLC, including its marketing business, customer contracts and its line space on the Colonial and Plantation pipelines, which is a significant part of our Refined Products and Renewables segment. We also entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion.

Year Ended March 31, 2017

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to ArcLight for approximately $112.4 million in cash. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Grassland

On November 29, 2016, we sold Grassland and received proceeds of $22.0 million. See Note 13 to our consolidated financial statements included in this Annual Report for a further discussion.

Year Ended March 31, 2018

Sale of Interest in Glass Mountain Pipeline, LLC (“Glass Mountain”)

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain for net proceeds of $292.1 million. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Crude Oil Logistics segment have not been classified as discontinued operations.

Sawtooth Joint Venture

On March 30, 2018, we completed the transaction to form a joint venture with Magnum Liquids, LLC, a portfolio company of Haddington Ventures LLC, along with Magnum Development, LLC and other Haddington-sponsored investment entities (collectively "Magnum") to focus on the storage of natural gas liquids and refined products by combining our Sawtooth salt dome storage facility with Magnum's refined products rights and adjacent leasehold. Magnum acquired an approximately 28.5% interest in Sawtooth from us, in exchange for consideration consisting of a cash payment of approximately $37.6 million (excluding working capital) and the contribution of certain refined products rights and adjacent leasehold. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of a Portion of Retail Propane Business

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC for net proceeds of $212.4 million in cash. The Retail Propane businesses subject to this transaction consisted of our operations across the Mid-Continent and Western portions of the United States. We retained our Retail Propane businesses located in the Eastern, mid-Atlantic and Southeastern sections of the United States. See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion.

Year Ended March 31, 2019

Sale of Interest in E Energy Adams, LLC

On May 3, 2018, we sold our previously held 20% interest in E Energy Adams, LLC for net proceeds of $18.6 million. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Remaining Retail Propane Business

On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior for total consideration of $889.8 million in cash. On August 14, 2018, we sold our previously held interest in Victory Propane. See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Bakken Saltwater Disposal Business

On November 30, 2018, we completed the sale of NGL Water Solutions Bakken, LLC to an affiliate of Tallgrass Energy, LP for $85.0 million in net cash proceeds and recorded a gain on disposal of $33.4 million during the year ended March 31, 2019. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Water Solutions segment have not been classified as discontinued operations.

Sale of South Pecos Water Disposal Business

On February 28, 2019, we completed the sale of our South Pecos water disposal business to a subsidiary of WaterBridge Resources LLC for $232.2 million in net cash proceeds and recorded a gain on disposal of $107.9 million during the year ended March 31, 2019. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Water Solutions segment have not been classified as discontinued operations.

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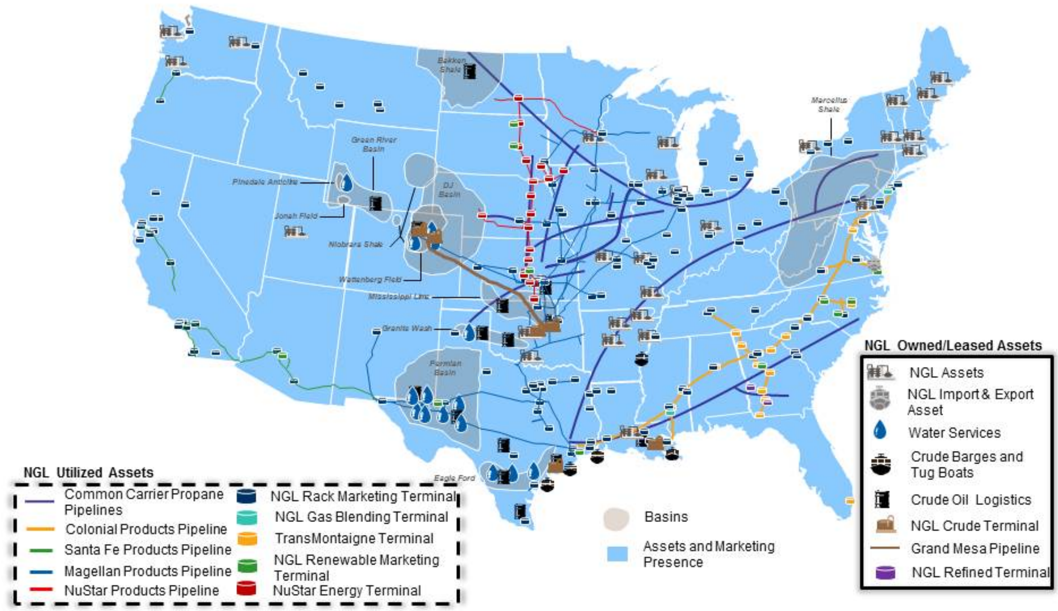
Primary Service Areas

The following map shows the primary service areas of our businesses at March 31, 2019:



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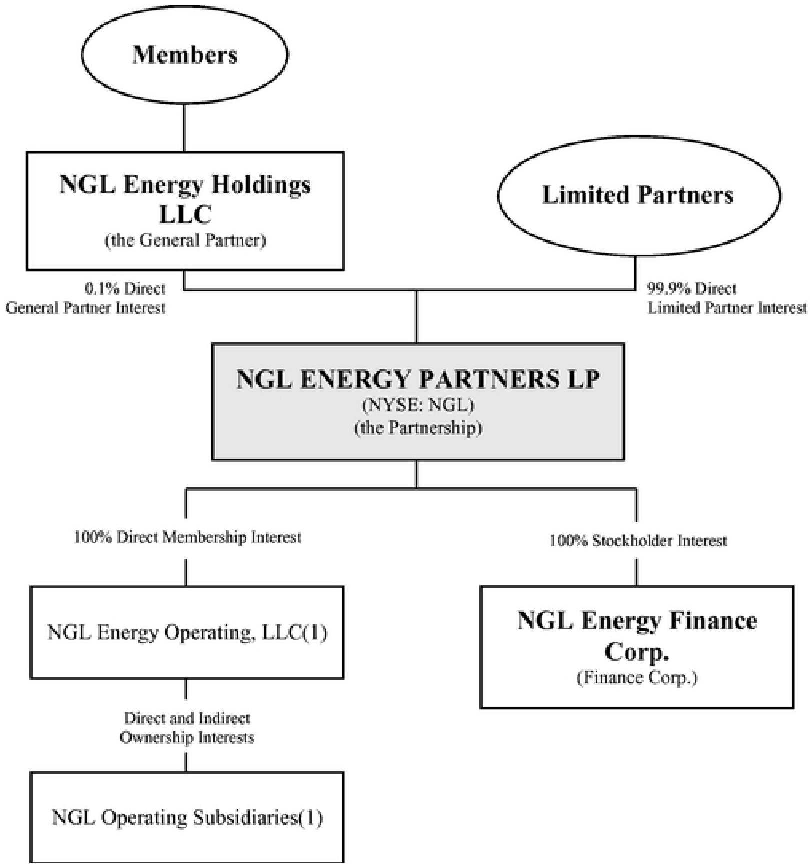
Organizational Chart

The following chart provides a summarized view of our legal entity structure at March 31, 2019:



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(1) Includes (i) NGL Crude Logistics, LLC, which includes the operations of our Crude Oil Logistics business and a portion of our Refined Products and Renewables businesses, (ii) NGL Water Solutions, LLC, which includes the operations of our Water Solutions business, (iii) NGL Liquids, LLC, which includes the operations of our Liquids business, and (iv) TransMontaigne, LLC, which includes the remaining portion of our Refined Products and Renewables businesses.

Our Business Strategies

Our principal business objectives are to maximize the profitability and stability of our businesses, grow our businesses in an accretive and prudent manner, and maintain a strong balance sheet. We intend to accomplish these objectives by executing the following strategies:

- *Focus on building a vertically integrated midstream master limited partnership providing multiple services to customers.* We continue to enhance our ability to transport crude oil from the wellhead to refiners, refined products from refiners to customers, wastewater from the wellhead to treatment for disposal, recycle, or discharge, and natural gas liquids from processing plants to end users.
- *Achieve organic growth by investing in new assets that increase volumes, enhance our operations, and generate attractive rates of return*. We believe that there are accretive organic growth opportunities that originate from assets we own and operate. We have invested and expect to continue to invest within our existing businesses, particularly within our Crude Oil Logistics and Water Solutions businesses as we grow these businesses with highly accretive, fee-based organic growth opportunities.
- *Deliver accretive growth through strategic acquisitions that complement our existing business model and expand our operations*. We intend to continue to pursue acquisitions that build upon our vertically integrated business model, add scale to our current operating platforms, and enhance our geographic diversity in our businesses. We have established a successful track record of acquiring companies and assets at attractive prices and we continue to evaluate acquisition opportunities in order to capitalize on this strategy in the future.
- *Focus on consistent annual cash flows by adding operations that minimize commodity price risk and generate fee-based, cost-plus, or margin-based revenues under multi-year contracts.* We intend to focus on long-term fee-based contracts in addition to back-to-back contracts which minimize commodity price exposure. We continue to increase cash flows that are supported by certain fee-based, multi-year contracts, some of which include acreage dedications from producers or volume commitments.
- *Maintain a disciplined cash distribution policy that complements our leverage, acquisition and organic growth strategies*. We target leverage levels that are consistent with those of investment grade companies. During the year ended March 31, 2019, we reduced our outstanding indebtedness by $528.2 million, including current maturities. We will seek to maintain sufficient liquidity and credit metrics to manage existing and future capital requirements and to take advantage of market opportunities, and expect to continue to evaluate the capital markets and may opportunistically pursue financing transactions to optimize our capital structure.

Our Competitive Strengths

We believe that we are well positioned to successfully execute our business strategies and achieve our principal business objectives because of the following competitive strengths:

- *Our vertically integrated and diversified operations, which help us generate more predictable and stable cash flows on a year-to-year basis.* Our ability to provide multiple services to customers in numerous geographic areas enhances our competitive position. Our four business units are diversified by geography, customer-base and commodity sensitivities which we believe provides us with the ability to maintain cash flows throughout typical commodity cycles. We believe that our Liquids business provides us with valuable market intelligence that helps us identify potential acquisition opportunities. Our Refined Products business benefits from lower energy prices driving increased customer demand, which can offset the downward pressure on our Crude Oil Logistics and Water Solutions businesses in a low price environment.
- *Our network of crude oil transportation assets, which allows us to serve customers over a wide geographic area and optimize sales.* Our strategically deployed railcar fleet, towboats, barges, and trucks, and our owned and contracted pipeline capacity, provide access to a wide range of customers and markets. We use this expansive network of transportation assets to deliver crude oil to the optimal markets.
- *Our water processing facilities, which are strategically located near areas of high crude oil and natural gas production*. Our water processing facilities are located among the most prolific crude oil and natural gas producing areas in the United States, including the Permian Basin, the DJ Basin, the Eagle Ford shale play and the Pinedale Anticline. In addition, we believe that the technological capabilities of our Water Solutions business can be quickly implemented at new facilities and locations.

- *Our network of natural gas liquids transportation, terminal, and storage assets, which allows us to provide multiple services over the continental United States.* Our strategically located terminals, large railcar fleet, shipper status on common carrier pipelines, and substantial leased and owned underground storage enable us to be a preferred purchaser and seller of natural gas liquids.
- *Our access to refined products pipeline and terminal infrastructure* . Our capacity allocations on third-party pipelines and our proprietary access to refined products terminals give us the opportunity to serve customers over a large geographic area.
- *Our seasoned management team with extensive midstream industry experience and a track record of acquiring, integrating, operating and growing successful businesses.* Our management team has significant experience managing companies in the energy industry, including master limited partnerships. In addition, through decades of experience, our management team has developed strong business relationships with key industry participants throughout the United States. We believe that our management's knowledge of the industry, relationships within the industry, and experience in identifying, evaluating and completing acquisitions provides us with opportunities to grow through strategic and accretive acquisitions that complement or expand our existing operations.

Our Businesses

Crude Oil Logistics

Overview. Our Crude Oil Logistics segment purchases crude oil from producers and marketers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets. Our operations are centered near areas of high crude oil production, such as the Bakken shale play in North Dakota, the DJ Basin in Colorado, the Permian Basin in Texas and New Mexico, the Eagle Ford shale play in Texas, the Anadarko Basin, including the STACK, SCOOP, Granite Wash and Mississippi Lime plays in Oklahoma and Texas, and southern Louisiana at the Gulf of Mexico.

We own a 550-mile pipeline that transports crude oil from its origin in Weld County, Colorado to Cushing, Oklahoma (the "Grand Mesa Pipeline"). Grand Mesa Pipeline commenced operations on November 1, 2016, and the main line portion of this pipe is comprised of a 37.5% undivided interest in a crude oil pipeline jointly owned with Saddlehorn Pipeline Company, LLC ("Saddlehorn") where we have the right to utilize 150,000 barrels per day of capacity. During the year ended March 31, 2019, there were approximately 117,000 barrels per day transported on the Grand Mesa Pipeline. Operating costs are allocated to us based on our proportionate ownership interest and throughput. We also own 970,000 barrels of operational tankage related to the Grand Mesa Pipeline.

Through our undivided interest in the Grand Mesa Pipeline, we have capacity sufficient to service our customer contracts at the same origin and termination points with the ability to accept additional volume commitments. We retained ownership of our previously-acquired easements for the potential future development of transportation projects involving petroleum commodities other than crude oil and condensate. With the consent and participation of Saddlehorn, we and Saddlehorn may consider future opportunities using these easements for projects involving the transportation of crude oil and condensate.

Operations. We purchase crude oil from producers and marketers and transport it to refineries or for resale. Our strategically deployed railcar fleet, towboats, barges, and trucks, and our owned and contracted pipeline capacity, provide access to a wide range of customers and markets. We use this expansive network of transportation assets to deliver crude oil to the optimal markets.

We currently transport crude oil using the following assets:

- 170 owned trucks and 248 owned trailers operating primarily in the Mid-Continent, Permian Basin, Eagle Ford shale play, and Rocky Mountain regions;
- 397 owned railcars (all of which are leased to third parties) and 246 leased railcars (all of which are subleased to third parties) operating primarily in Arizona, California, Colorado, Florida, Louisiana, New Mexico, Oklahoma, Oregon, Texas, and Washington as well as Mexico; and
- 10 owned towboats and 19 owned barges operating primarily in the intercoastal waterways of the Gulf Coast and along the Mississippi and Arkansas river systems.

Of our 397 owned railcars, all are crude oil compliant with the standards for railcars built subsequent to 2011. Of our 246 leased railcars, 210 are crude oil compliant with the standards for railcars built subsequent to 2011 (see Part I, Item 1A–"Risk Factors").

We contract for truck, rail, and barge transportation services from third parties and ship on 20 common carrier pipelines. We own 27 pipeline injection stations, the locations of which are summarized below.

State	Number of Pipeline Injection Stations
Texas	14
Oklahoma	6
New Mexico	5
Kansas	2
Total	27

We also have commitments on several interstate pipelines for transportation of crude oil.

We own six storage terminal facilities. The largest of these is a terminal in Cushing, Oklahoma with a storage capacity of 3,626,602 barrels. The combined storage capacity of the other five terminals is 1,605,242 barrels.

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain. Glass Mountain is a 210-mile crude oil pipeline that originates in western Oklahoma and terminates in Cushing, Oklahoma. This pipeline, which became operational in February 2014, has a capacity of 147,000 barrels per day.

Customers. Our customers include crude oil refiners, producers, and marketers. During the year ended March 31, 2019, 79% of the revenues of our Crude Oil Logistics segment were generated from our ten largest customers of the segment. In addition to utilizing our assets to transport crude oil we own, we also provide truck transportation, barge transportation, storage, and terminal throughput services to our customers.

Competition. Our Crude Oil Logistics business faces significant competition, as many entities are engaged in the crude oil logistics business, some of which are larger and have greater financial resources than we do. The primary factors on which we compete are:

- price;
- availability of supply;
- reliability of service;
- logistics capabilities, including the availability of railcars, proprietary terminals, and owned pipelines, barges, railcars, trucks, and towboats;
- long-term customer relationships; and
- the acquisition of businesses.

Supply. We obtain crude oil from a large base of suppliers, which consists primarily of crude oil producers. We currently purchase crude oil from approximately 200 producers at approximately 2,300 leases.

Pricing Policy. Most of our contracts to purchase or sell crude oil are at floating prices that are indexed to published rates in active markets such as Cushing, Oklahoma. We seek to manage price risk by entering into purchase and sale contracts of similar volumes based on similar indexes and by hedging exposure due to fluctuations in actual volumes and scheduled volumes.

Our profitability is impacted by forward crude oil prices. Crude oil markets can either be in contango (a condition in which forward crude oil prices are greater than spot prices) or can be in backwardation (a condition in which forward crude oil prices are lower than spot prices). Our Crude Oil Logistics business benefits when the market is in contango, as increasing prices result in inventory holding gains during the time between when we purchase inventory and when we sell it. In addition, we are able to better utilize our storage assets when contango markets justify storing barrels. When markets are in backwardation, falling prices typically have an unfavorable impact on our margins.

Billing and Collection Procedures. Our Crude Oil Logistics customers consist primarily of crude oil refiners, producers, and marketers. We typically invoice these customers on a monthly basis. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on these customers. We believe the following procedures enhance our collection efforts with these customers:

- we require certain customers to prepay or place deposits for our products and services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our Crude Oil Logistics segment operates primarily under the NGL Crude Logistics, NGL Crude Transportation and NGL Marine trade names.

Water Solutions

Overview. Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services and sells freshwater to producers for exploration and production activities. Our water processing facilities are strategically located near areas of high crude oil and natural gas production, including the Midland Basin in Texas and Delaware Basin in Texas and New Mexico, the DJ Basin in Colorado, the Eagle Ford shale play in Texas, and the Pinedale Anticline in Wyoming. During the year ended March 31, 2019, we took delivery of 345.7 million barrels of wastewater, an average of 947,000 barrels per day.

Our Water Solutions segment engages in solids disposal with specialized equipment at select facilities in the Eagle Ford shale play, the Permian Basin, and the DJ Basin, which enables us to accept and dispose of solids such as tank bottoms, drilling fluids and drilling muds generated by crude oil and natural gas exploration and production activities. Our facilities will accept only exploration and production exempt waste allowed under our current permits.

Our Water Solutions segment is in the freshwater business in New Mexico and Texas. During the year ended March 31, 2019, we acquired two ranches and four freshwater facilities (including 45 freshwater wells).

Operations. We own 82 water treatment and disposal facilities, including 137 injection wells. The location and permitted processing capacities of these facilities and whether the facilities are located on lands we own or lease are summarized below.

Location	Number of Facilities	Permitted Processing Capacity (barrels per day) Own	Lease	Total
Permian Basin				
Delaware Basin (1) - Texas and New Mexico	26	1,431,000	55,000	1,486,000
Midland Basin (1) - Texas	15	400,800	—	400,800
Eagle Ford (1)(2) - Texas	24	634,000	292,000	926,000
DJ Basin - Colorado	13	345,500	150,000	495,500
Granite Wash (1) - Texas	2	60,000	—	60,000
Pinedale Anticline (3) - Wyoming	1	—	60,000	60,000
Eaglebine - Texas	1	20,000	—	20,000
Total - All Facilities	82	2,891,300	557,000	3,448,300

(1) Certain facilities can dispose of both wastewater and solids such as tank bottoms, drilling fluids and drilling muds.

(2) Includes one facility with a permitted processing capacity of 40,000 barrels per day in which we own a 75% interest.

(3) This facility has a design capacity of 60,000 barrels per day to process water to a recycle standard.

Our customers bring wastewater generated by crude oil and natural gas exploration and production operations to our facilities for treatment through pipeline gathering systems and by truck. Our pipeline delivered volumes will continue to increase as new projects come on line. Once we take delivery of the water, the level of processing is determined by the ultimate disposition of the water. Our solids customers bring solids generated by crude oil and natural gas exploration and production operations to our facilities by truck.

Our facilities in Colorado, Texas and New Mexico dispose of wastewater primarily into deep underground formations via injection wells.

Our facility servicing the Pinedale Anticline in Wyoming has the assets and technology needed to treat the water more extensively than a typical disposal facility. At this facility, the water is recycled, rather than being disposed of in an injection well. We either process the water to the point where it can be returned to producers to be reused in future drilling operations (recycle quality water), or we treat the water to a greater extent, such that it exceeds the standards for drinking water, and can be returned to the ecosystem (discharge quality water). Recycling offers producers an alternative to the use of fresh water in hydraulic fracturing operations. This minimizes the impact on aquifers, particularly in arid regions of the United States. Since June 2012, we have recycled approximately 19.4 million barrels (815 million gallons) of recycle quality water, have returned approximately 9.0 million barrels (378 million gallons) of discharge quality water back to New Fork River, which is a tributary of the Colorado River, and have returned approximately 2.6 million barrels (109 million gallons) of water to the ecosystem through an agricultural irrigation system.

At our disposal facilities, we use proprietary well maintenance programs to enhance injection rates and extend the service lives of the wells.

Customers. The customers of our Wyoming and Colorado facilities consist primarily of large exploration and production companies that conduct drilling operations near our facilities. The customers of our Texas and New Mexico facilities consist of both wastewater transportation companies and producers. The primary customer of our Wyoming facility has committed to deliver a specified minimum volume of water to our facility under a long-term contract. The primary customers of our Colorado facilities have committed to deliver all wastewater produced at wells within the DJ Basin to our facilities. Most customers of our other facilities are not under volume commitments, although many of our facilities have acreage dedications or are connected to producer facilities by pipeline. During the year ended March 31, 2019, 48% of the water treatment and disposal revenues of our Water Solutions segment were generated from our ten largest customers of the segment.

Competition. We compete with other processors of wastewater to the extent that other processors have facilities geographically close to our facilities. Location is an important consideration for our customers, who seek to minimize the cost of transporting the wastewater to disposal facilities. Our facilities are strategically located near areas of high crude oil and natural gas production. A significant factor affecting the profitability of our Water Solutions segment is the extent of exploration and production in the areas near our facilities, which is generally based upon producers' expectations about the profitability of drilling and producing new wells.

Pricing Policy. We charge customers a fee per barrel of wastewater processed. Certain contracts require the customer to deliver a specified minimum volume of wastewater over a specified period of time. We also generate revenue from the sale of hydrocarbons we recover in the process of treating the wastewater, which we take into consideration in negotiating the processing fees with our customers. We also charge pipeline transportation fees, pipeline interconnection fees and solids disposal fees to our customers.

Billing and Collection Procedures. Our Water Solutions customers consist of large exploration and production companies and also wastewater transportation companies and producers. We typically invoice these customers on a monthly basis. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on these customers. We believe the following procedures enhance our collection efforts with these customers:

- we require certain customers to prepay or place deposits for our services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend service to customers that have not timely paid invoices.

Trade Names. Our Water Solutions segment operates primarily under the NGL Water Solutions and Anticline Disposal trade names.

Technology. We hold multiple patents for processing technologies. We believe that the technological capabilities of our Water Solutions business can be quickly implemented at new facilities and locations.

Liquids

Overview. Our Liquids segment provides natural gas liquids procurement, storage, transportation, and supply services to customers through assets owned by us and third parties. Our Liquids business supplies propane to third-party retailers and wholesalers and butanes and natural gasolines to refiners and producers for use as blending stocks and diluent and assist refineries by managing their seasonal butane supply needs. During the year ended March 31, 2019, we sold 2.5 billion gallons of natural gas liquids, an average of 6.83 million gallons per day.

Operations. We procure natural gas liquids from refiners, gas processing plants, producers and other resellers for delivery to leased or owned storage space, common carrier pipelines, railcar terminals, and direct to certain customers. Our customers take delivery by loading natural gas liquids into transport vehicles from common carrier pipeline terminals, private terminals, our terminals, directly from refineries and rail terminals, and by railcar.

A portion of our wholesale propane gallons are presold to third-party retailers and wholesalers at a fixed price under back-to-back contracts. Back-to-back contracts, in which we balance our contractual portfolio by buying physical propane supply or derivatives when we have a matching purchase commitment from our wholesale customers, protect our margins and mitigate commodity price risk. Presales also reduce the impact of warm weather because the customer is required to take delivery of the propane regardless of the weather or any other factors. We generally require cash deposits from these customers. In addition, on a daily basis we have the ability to balance our inventory by buying or selling propane, butanes, and natural gasoline to refiners, resellers, and propane producers through pipeline inventory transfers at major storage hubs.

In order to secure consistent supply during the heating season, we are often required to purchase volumes of propane during the entire fiscal year. In order to mitigate storage costs and price risk, we may sell those volumes at a lesser margin than we earn in our other wholesale operations.

We purchase butane from refiners during the summer months, when refiners have a greater butane supply than they need, and sell butane to refiners during the winter blending season, when demand for butane is higher. We utilize a portion of our railcar fleet and a portion of our leased underground storage to store butane for this purpose.

We also transport customer-owned natural gas liquids on our leased railcars and charge the customers a transportation service fee as well as subleasing railcars to certain customers.

We own 27 natural gas liquids terminals and we lease a fleet of approximately 4,600 high-pressure and general purpose railcars (of which 125 railcars are subleased to third parties). These assets give us the opportunity to access wholesale markets throughout the United States, and to move product to locations where demand is highest. We utilize these terminals and railcars primarily in the service of our wholesale propane, butane and asphalt operations. At the underground storage facility near Delta, Utah, and our facilities at Kingfisher, Oklahoma and Port Hudson, Louisiana, we provide transportation, storage, and throughput services to third parties.

The location of our facilities (excluding the underground storage facility near Delta, Utah) and their throughput capacity are summarized below.

Facility	Throughput Capacity (gallons per day)	Terminal Interconnects
Arkansas	2,422,800	Connected to Enterprise Texas Eastern Products Pipeline; Rail Facility
Missouri	1,813,000	Connected to Phillips66 Blue Line Pipeline
Minnesota	1,441,000	Connected to Enterprise Mid-America Pipeline; Rail Facility
Indiana	1,364,000	Connected to Enterprise Texas Eastern Products Pipeline; Rail Facility
Louisiana	945,000	Truck Facility
Illinois	864,000	Connected to Phillips66 Blue Line Pipeline
Wisconsin	863,000	Connected to Enterprise Mid-America Pipeline; Rail Facility
Oklahoma	756,800	Connected to Phillips66 Chisholm Pipeline; Rail Facility
Washington	717,000	Rail Facility
Virginia	684,000	Rail Facility; Marine Facility
Massachusetts	681,200	Rail Facility
Vermont	387,000	Rail Facility
Maine	386,400	Rail Facility
New York	386,400	Rail Facility
Pennsylvania	368,000	Rail Facility
United States Total	14,079,600	
Ontario, Canada	200,000	Truck Facility
Canada Total	200,000	
Total	14,279,600	

We have operating agreements with third parties for certain of our terminals. The terminals in East St. Louis, Illinois and Jefferson City, Missouri are operated for us by a third party for a monthly fee under an operating and maintenance agreement that expires in November 2022. The terminal in St. Catherines, Ontario, Canada is operated by a third party under a year-to-year agreement.

We own the land on which 13 of the 27 natural gas liquids terminals are located and we either have easements or lease the land on which the remaining terminals are located.

We are the majority owner of an underground storage facility near Delta, Utah. This facility currently has capacity to store approximately 6.0 million barrels of natural gas liquids and refined products. We lease storage to approximately 16 customers, with lease terms ranging from one to three years. The facility is located on property for which we have a long-term lease.

We own a natural gas liquids terminal that supports refined products blending in Port Hudson, Louisiana, and a natural gas liquids and condensate facility in Kingfisher, Oklahoma. The Port Hudson Terminal is located near Baton Rouge, Louisiana, and is in proximity to other refined products infrastructure along the Colonial pipeline. This truck unloading and storage facility allows for the aggregation and supply of butane and naphtha for motor fuel blending and consists of storage tanks with total capacity of 720,000 gallons. The Kingfisher Facility is a natural gas liquids and condensate facility located in Kingfisher, Oklahoma, which is located in the middle of the STACK production region. The facility connects to the Chisholm NGL pipeline and the Conway Fractionation complex and consists of 450,000 gallons of storage capacity, a methanol extraction tower and a 5,000-barrel per day condensate splitter.

In March 2019, we completed the acquisition of the natural gas liquids terminal business of DCP Midstream, LP. The acquisition consisted of five propane rail terminals, located in the Eastern United States, a 50% ownership interest in an additional rail terminal, located in the state of Maine, and an import/export terminal located in Chesapeake, Virginia. The import/export terminal has the capability to load and unload ships ranging in size from handy-sized vessels up to very large gas carriers. These terminals complement our existing natural gas liquids portfolio and also create additional opportunities for new and existing customers to supply their business. The terminals we purchased in this acquisition are included in the throughput capacity per day table above.

We own 23 transloading units, which enable customers to transfer product from railcars to trucks. These transloading units can be moved to locations along a railroad where it is most convenient for customers to transfer their product.

We lease natural gas liquids storage space to accommodate the supply requirements and contractual needs of our retail and wholesale customers. We lease storage space for natural gas liquids in various storage hubs in Kansas, Mississippi, Missouri, Texas and Canada.

The following table summarizes our significant leased storage space at natural gas liquids storage facilities and interconnects to those facilities:

	Leased Storage Space (gallons)		
Storage Facility	**Beginning April 1, 2019**	**At March 31, 2019**	**Storage Interconnects**
Kansas	67,200,000	67,200,000	Connected to Enterprise Mid-America Pipeline, NuStar Pipelines and ONEOK North System Pipeline; Rail Facility; Truck Facility
Mississippi	6,300,000	9,660,000	Connected to Enterprise Dixie Pipeline; Rail Facility
Missouri	7,560,000	7,560,000	Truck Facility
Texas	3,990,000	6,510,000	Connected to Enterprise Texas Eastern Products Pipeline; Truck Facility
Michigan	1,050,000	—	Rail Facility; Truck Facility
United States Total	86,100,000	90,930,000	
Ontario, Canada	15,750,000	23,179,000	Rail Facility
Alberta, Canada	3,440,800	3,441,000	Connected to Cochin Pipeline; Rail Facility
Canada Total	19,190,800	26,620,000	
Total	105,290,800	117,550,000	

Customers. Our Liquids business serves approximately 950 customers in 47 states. Our Liquids business serves national, regional and independent retail, industrial, wholesale, petrochemical, refiner and natural gas liquids production customers. We deliver the propane supply to our customers at terminals located on common carrier pipelines, rail terminals, refineries, and major United States propane storage hubs. During the year ended March 31, 2019, 27% of the revenues of our Liquids segment were generated from our ten largest customers of the segment.

Seasonality. Our wholesale Liquids business is largely seasonal as the primary users of propane as heating fuel generally purchase propane during the typical fall and winter heating season. However, we are able to partially mitigate the effects of seasonality by preselling a portion of our wholesale volumes to retailers and wholesalers and requiring the customer to take delivery of the product regardless of the weather.

Competition. Our Liquids business faces significant competition, as many entities, including other natural gas liquids wholesalers and companies involved in the natural gas liquids midstream industry (such as terminal and refinery operations), are engaged in the liquids business, some of which have greater financial resources than we do. The primary factors on which we compete are:

- price;
- availability of supply;
- reliability of service;
- available space on common carrier pipelines;
- storage availability;

- logistics capabilities, including the availability of railcars, and proprietary terminals;
- long-term customer relationships; and
- the acquisition of businesses.

Pricing Policy. In our Liquids business, we offer our customers three categories of contracts for propane sourced from common carrier pipelines:

- customer pre-buys, which typically require deposits based on market pricing conditions;
- market based, which can either be a posted price or an index to spot price at time of delivery; and
- load package, a firm price agreement for customers seeking to purchase specific volumes delivered during a specific time period.

We use back-to-back contracts for many of our Liquids segment sales to limit exposure to commodity price risk and protect our margins. We are able to match our supply and sales commitments by offering our customers purchase contracts with flexible price, location, storage, and ratable delivery. However, certain common carrier pipelines require us to keep minimum in-line inventory balances year round to conduct our daily business, and these volumes are not matched with a sales commitment.

We generally require deposits from our customers for fixed price future delivery of propane if the delivery date is more than 30 days after the time of contractual agreement.

Billing and Collection Procedures. Our Liquids segment customers consist of commercial accounts varying in size from local independent distributors to large regional and national retailers. These sales tend to be large volume transactions that can range from 10,000 gallons up to 1,000,000 gallons, and deliveries can occur over time periods extending from days to as long as a year. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on these customers. We believe the following procedures enhance our collection efforts with these customers:

- we require certain customers to prepay or place deposits for their purchases;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we require certain customers to take delivery of their contracted volume ratably to help control the account balance rather than allowing them to take delivery of propane at their discretion;
- we review receivable aging analysis regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our Liquids segment operates primarily under the NGL Supply Wholesale, NGL Supply Terminal Company, Sawtooth Caverns, Centennial Energy, and Centennial Gas Liquids trade names.

Refined Products and Renewables

Overview. Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties. During the year ended March 31, 2019, we sold 173.5 million barrels of gasoline, 53.7 million barrels of diesel, 2.6 million barrels of ethanol and 1.0 million barrels of biodiesel.

Operations. The refined products we handle include gasoline, diesel, and heating oil. We purchase refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedule them for delivery at various locations throughout the country. On certain interstate refined products pipelines, shipment demand exceeds available capacity, and capacity is allocated to shippers based on their historical shipment volumes. We hold allocated capacity on the Colonial and Plantation pipelines.

A significant percentage of our business is priced on a back-to-back basis which minimizes our commodity price exposure. We sell our products to commercial and industrial end users, independent retailers, distributors, marketers, government entities, and other wholesalers of refined petroleum products. We sell our products at terminals owned by third parties. As discussed in “Dispositions” above, on February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. As part of this transaction, we retained TransMontaigne Product Services LLC, including its marketing business, customer contracts and its line space on the Colonial and Plantation pipelines, which is a significant part of our Refined Products and Renewables segment. We also entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system.

The following table summarizes our leased storage space at refined products storage facilities:

Locations	Active Storage Capacity (shell barrels)
Southeast Facilities	
Virginia	2,288,000
Georgia	1,953,000
Mississippi	1,594,000
New Jersey	1,281,000
North Carolina	775,000
Alabama	178,000
South Carolina	166,000
Florida	62,000
Total Southeast Facilities Storage Capacity (1)	8,297,000
Mid-Continent Facilities	
Magellan North system	985,000
NuStar East Products system	390,000
Total Mid-Continent Facilities Storage Capacity	1,375,000
West Facilities	
Kinder Morgan (Phoenix, Arizona)	50,000
Buckeye Terminals, LLC	1,000
Total West Facilities Storage Capacity	51,000
Total Facilities Storage Capacity	9,723,000

(1) Includes 235,400 barrels of capacity that is subleased to third parties.

In January 2019, we acquired two refined products terminals located in Georgia. These terminals have a combined refined products storage capacity of 170,000 shell barrels, ethanol storage capacity of 23,000 shell barrels and transmix storage capacity of 900 shell barrels.

We purchase ethanol primarily at production facilities in the Midwest and transport the ethanol via trucks and railcars for sale at various locations. We also blend ethanol into gasoline for sale to customers at third party terminals. We market and handle logistics for third-party ethanol manufacturers for a service fee. We primarily purchase biodiesel from production facilities in the Midwest and in Houston, Texas, and transport the biodiesel via railcar to sell to customers. We lease 22,000 barrels of biodiesel storage at a fuel terminal in Phoenix, Arizona and also have a biodiesel terminaling agreement at a fuel terminal in Phoenix, Arizona with a minimum monthly throughput requirement. We lease 346 railcars for the transportation of renewables, of which 299 railcars are subleased to a third party.

Customers. Our Refined Products and Renewables segment serves customers in 37 states. During the year ended March 31, 2019, 40% of the revenues of our Refined Products and Renewables segment were generated from our ten largest customers of the segment. We sell to customers via rack spot sales, contract sales, bulk sales, and just-in-time sales.

Contract sales are made pursuant to negotiated contracts, generally ranging from one to twelve months in duration, that we enter into with local market wholesalers, independent gasoline station chains, heating oil suppliers, and other customers. Contract sales provide these customers with a specified volume of product during the term of the agreement.

Delivery of product sold under these arrangements generally is at third party truck racks. The pricing of the product delivered under a majority of our contract sales is based on published index prices, and varies based on changes in the applicable indices. In addition, at the customer's option, the contract price may be fixed at a stipulated price per gallon.

Rack spot sales are sales that do not involve continuing contractual obligations to purchase or deliver product. Rack spot sales are priced and delivered on a daily basis through truck loading racks. At the end of each day for each of the terminals that we market from, we establish the next day selling price for each product for each of our delivery locations. We announce or "post" to customers via website, e-mail, and telephone communications the rack spot sale price of various products for the following morning. Typical rack spot sale purchasers include commercial and industrial end users, independent retailers and small, independent marketers who resell product to retail gasoline stations or other end users. Our selling price of a particular product on a particular day is a function of our supply at that delivery location or terminal, our estimate of the costs to replenish the product at that delivery location, and our desire to reduce inventory levels at that particular location that day.

Bulk sales generally involve the sale of products in large quantities in the major cash markets including the Houston Gulf Coast and New York Harbor. A bulk sale of products also may be made while the product is being transported on common carrier pipelines.

We conduct just-in-time sales at a nationwide network of terminals owned by third parties. We post prices at each of these locations on a daily basis. When customers decide to purchase product from us, we purchase the same volume of product from a supplier at a previously agreed-upon price. For these just-in-time transactions, our purchase from the supplier occurs at the same time as our sale to our customer.

Seasonality. The demand for gasoline typically peaks during the summer driving season, which extends from April to September, and declines during the fall and winter months. However, the demand for diesel typically peaks during the fall and winter months due to colder temperatures in the Northeast, and peaks in the Midwest during spring planting and fall harvest.

Competition. Our Refined Products and Renewables business faces significant competition, as many entities are engaged in the refined products and renewables business, some of which have greater financial resources than we do. The primary factors on which we compete are:

- price;
- availability of supply;
- reliability of service;
- available space on common carrier pipelines;
- storage availability;
- logistics capabilities, including the availability of railcars, and proprietary terminals; and
- long-term customer relationships.

Market Price Risk. Our philosophy is to maintain minimum commodity price exposure through a combination of purchase contracts, sales contracts and financial derivatives. A significant percentage of our business is priced on a back-to-back basis which minimizes our commodity price exposure. For discretionary inventory, and for those instances where physical transactions cannot be appropriately matched, we utilize financial derivatives to mitigate commodity price exposure. Specific exposure limits are mandated in our credit agreement and in our market risk policy.

The value of refined products in any local delivery market is the sum of the commodity price as reflected on the NYMEX and the basis differential for that local delivery market. The basis differential for any local delivery market is the spread between the cash price in the physical market and the quoted price in the futures markets for the prompt month. We typically utilize NYMEX futures contracts to mitigate commodity price exposure. We generally do not manage the financial impact on us from changes in basis differentials affected by local market supply and demand disruptions.

Legal and Regulatory Considerations . Demand for ethanol and biodiesel is driven in large part by government mandates and incentives. Refiners and producers are required to blend a certain percentage of renewables into their refined products, although the percentage can vary from year to year based on the United States Environmental Protection Agency ("EPA") mandates. In addition, the federal government has in recent years granted certain tax credits for the use of biodiesel, although on several occasions these tax credits have expired. In February 2018, the federal government passed a law to reinstate the tax credit retroactively to January 1, 2017, with the credit expiring on December 31, 2017. Legislation is pending in Congress (e.g., H.R. 2089 proposed by Representative Abby Finkenauer (D-IA) and S. 1288 proposed by Senator Ron Wyden (D-OR) that would, if passed and signed into law, further extend these tax credits. Changes in future mandates and incentives, or decisions by the federal government related to future reinstatement of the biodiesel tax credit, could result in changes in demand for ethanol and biodiesel.

Billing and Collection Procedures. Our Refined Products and Renewables customers consist primarily of commercial and industrial end users, independent retailers, distributors, marketers, government entities, and other wholesalers of refined petroleum products. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on our Refined Products and Renewables customers. We believe the following procedures enhance our collection efforts with our customers:

- we require certain customers to prepay or place deposits for our products and services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we monitor individual customer receivables relative to previously-approved credit limits, and our automated rack delivery system gives us the option to discontinue providing product to customers when they exceed their credit limits;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our Refined Products and Renewables segment operates primarily under the NGL Crude Logistics and TransMontaigne Product Services LLC trade names.

Employees

At March 31, 2019, we had approximately 1,300 full-time employees. We do not have any employees that are members of a labor union.

Government Regulation

Regulation of the Oil and Natural Gas Industries

Regulation of Oil and Natural Gas Exploration, Production and Sales. Sales of crude oil and natural gas liquids are not currently regulated and are transacted at market prices. In 1989, the United States Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. The Federal Energy Regulatory Commission ("FERC"), which has authority under the Natural Gas Act to regulate the prices and other terms and conditions of the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all natural gas resellers subject to its regulation, except interstate pipelines, to resell natural gas at market prices. Either Congress or the FERC (with respect to the resale of natural gas in interstate commerce), however, could re-impose price controls in the future.

Exploration and production operations and water disposal facilities are subject to various types of federal, state and local regulation, including, but not limited to, permitting, well location, methods of drilling, well operations, and conservation of resources. While these regulations do not directly apply to our business, they may affect the businesses of certain of our customers and suppliers and thereby indirectly affect our business.

Regulation of the Transportation and Storage of Natural Gas and Oil and Related Facilities. The FERC regulates oil pipelines under the Interstate Commerce Act and natural gas pipeline and storage companies under the Natural Gas Act, and Natural Gas Policy Act of 1978 (the "NGPA"), as amended by the Energy Policy Act of 2005. The Grand Mesa Pipeline became operational on November 1, 2016 and has several points of origin in Colorado, runs from those origin points through Kansas and terminates in Cushing, Oklahoma. The transportation services on the Grand Mesa Pipeline are subject to FERC regulation. In February 2018, the FERC issued a revised policy to disallow income tax allowance cost recovery in rates charged by pipeline companies organized as master limited partnerships. The FERC's revised policy impacts cost-of-service rates on oil pipelines. Currently, the volumes of crude oil that are transported on the Grand Mesa Pipeline are subject to contractual agreements. Therefore, the FERC's revised policy is not expected to impact the Grand Mesa Pipeline at the present time. Additionally, contracts we enter into for the interstate transportation or storage of crude oil or natural gas may be subject to FERC regulation including reporting or other requirements. In addition, the intrastate transportation and storage of crude oil and natural gas is subject to regulation by the state in which such facilities are located, and such regulation can affect the availability and price of our supply, and have both a direct and indirect effect on our business.

Anti-Market Manipulation. We are subject to the anti-market manipulation provisions in the Natural Gas Act and the NGPA, which authorizes the FERC to impose fines of up to $1 million per day per violation of the Natural Gas Act, the NGPA, or their implementing regulations. In addition, the Federal Trade Commission ("FTC") holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in petroleum markets, including the authority to request that a court impose fines of up to $1 million per violation. These agencies have promulgated broad rules and regulations prohibiting fraud and manipulation in oil and gas markets. The Commodity Futures Trading Commission ("CFTC") is directed under the Commodity Exchange Act to prevent price manipulations in the commodity and futures markets, including the energy futures markets. Pursuant to statutory authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1 million per day per violation or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the Commodity Exchange Act. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation.

Maritime Transportation. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. Since we engage in maritime transportation through our barge fleet between locations in the United States, we are subject to the provisions of the law. As a result, we are responsible for monitoring the ownership of our subsidiaries that engage in maritime transportation and for taking any remedial action necessary to ensure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flagged vessels be manned by United States citizens. Foreign-flagged seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flagged vessel operations compared to foreign-flagged vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flagged vessel owners. The United States Coast Guard and American Bureau of Shipping maintain the most stringent regimen of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flagged operators than for owners of vessels registered under foreign flags of convenience.

Environmental Regulation

General. Our operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. Accordingly, 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 or imposing additional costs on our operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species, and limiting or prohibiting construction activities during certain sensitive periods, such as when threatened or endangered species are breeding/nesting;
- delaying construction or system modification or upgrades during permit issuance or renewal;
- 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 or permit requirements issued pursuant to or imposed by 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 such as hydrocarbons or wastes have been disposed or otherwise released. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate.

The following is a discussion of the material environmental laws and regulations that relate to our businesses.

Hazardous Substances and Waste. We are subject to various federal, state, and local environmental laws and regulations governing the storage, distribution and transportation of natural gas liquids and the operation of bulk storage liquefied petroleum gas (LPG) terminals, as well as laws and regulations governing environmental protection, including those addressing the discharge of materials into the environment or otherwise relating to protection of the environment. Generally, these laws (i) regulate air and water quality and impose limitations on the discharge of pollutants and establish standards for the handling of solid and hazardous wastes; (ii) subject our operations to certain permitting and registration requirements; (iii) may result in the suspension or revocation of necessary permits, licenses and authorizations; (iv) impose substantial liabilities on us for pollution resulting from our operations; (v) require remedial measures to mitigate pollution from former or ongoing operations; and (vi) may result in the assessment of administrative, civil and criminal penalties for failure to comply with such laws. These laws include, among others, the Resource Conservation and Recovery Act ("RCRA"), the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the federal Clean Air Act, the Homeland Security Act of 2002, the Emergency Planning and Community Right to Know Act, the Clean Water Act, the Safe Drinking Water Act, and comparable state statutes. For example, as a flammable substance, propane is subject to risk management plan requirements under section 112(r) of the federal Clean Air Act.

CERCLA, also known as the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past 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. While natural gas liquids are not a hazardous substance within the meaning of CERCLA, other chemicals used in or generated by our operations may be classified as a hazardous substance. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to strict and joint and several liability for the costs of investigating and cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

RCRA, and comparable state statutes and their implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Certain wastes associated with the production of oil and natural gas, as well as certain types of petroleum-contaminated media and debris, are excluded from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is possible, however, that certain wastes now classified as non-hazardous could be classified as hazardous wastes in the future and therefore be subject to more rigorous and costly disposal requirements. Legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas wastes as "hazardous wastes." Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our consolidated results of operations and financial position.

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 groundwater) or to implement remedial measures to prevent or mitigate future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our consolidated results of operations or financial position.

Oil Pollution Prevention. Our operations involve the shipment of crude oil by barge through navigable waters of the United States. The Oil Pollution Prevention Act imposes liability for releases of crude oil from vessels or facilities into navigable waters. If a release of crude oil to navigable waters occurred during shipment or from a terminal, we could be subject to liability under the Oil Pollution Prevention Act. We are not currently aware of any facts, events, or conditions related to oil spills that could materially impact our consolidated results of operations or financial position. In 1973, the EPA adopted oil pollution prevention regulations under the Clean Water Act. These oil pollution prevention regulations, as amended several times since their original adoption, require the preparation of a Spill Prevention Control and Countermeasure ("SPCC") plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming crude oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. Where applicable, we maintain and implement such plans for our facilities.

Air Emissions. 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, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain permits prior to 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. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. Furthermore, we may 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 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 United States and impose requirements affecting our ability to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. 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 or other constituent 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. We maintain a number of discharge permits, some of which may require us to monitor and sample the storm water runoff from such 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.

Underground Injection Control. Our underground injection operations are subject to the Safe Drinking Water Act, as well as analogous state laws and regulations, which establish requirements for permitting, testing, monitoring, record keeping, and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our permits, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries.

Hydraulic Fracturing. 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. We do not conduct any hydraulic fracturing activities. However, a portion of our customers' crude oil and natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process, and our Water Solutions business treats and disposes of wastewater generated from natural gas production, including production utilizing hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate oil and gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of Congress. Congress will likely continue to consider legislation to amend the Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under the Act's Underground Injection Control Program and/or require disclosure of chemicals used in the hydraulic fracturing process. Federal agencies, including the EPA and the United States Department of the Interior, have asserted their regulatory authority to, for example, study the potential impacts of hydraulic fracturing on the environment, and initiate rulemakings to compel disclosure of the chemicals used in hydraulic fracturing operations, and establish pretreatment standards for wastewater from hydraulic fracturing operations. In addition, some states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing, which include additional permit requirements, public disclosure of fracturing fluid contents, operational restrictions, and/or temporary or permanent bans on hydraulic fracturing. We expect that scrutiny of hydraulic fracturing activities will continue in the future.

Greenhouse Gas Regulation

There is a growing concern, both nationally and internationally, about climate change and the contribution of greenhouse gas emissions, most notably carbon dioxide, to global warming. This growing concern has resulted in a steady stream of legislation considered by Congress to address climate change through a variety of mechanisms, including carbon taxes and carbon cap-and-trade programs. For example, on January 24, 2019, Representative Theodore E. Deutch (D-FL) introduced H.R. 763, the Energy Innovation and Carbon Dividend Act of 2019, which would impose a fee on the carbon content of fuels, including crude oil and natural gas, on the producers or importers of such fuels. On April 10, 2019, Senator Sheldon Whitehouse (D-RI) introduced S. 1128, the American Opportunity Carbon Fee Act of 2019, which would impose fees on emissions from natural gas, petroleum products, and coal. The ultimate outcome of any possible future federal legislative initiatives is uncertain. In addition, several states have already adopted some legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings allowed the EPA to adopt and implement regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. On May 12, 2016, the EPA finalized three rules that regulate greenhouse gas emissions from certain sources in the oil and natural gas industry, including New Source Performance Standards for the Oil and Natural Gas Sector, which became effective on August 2, 2016. On April 18, 2017, the EPA announced its intention to reconsider certain aspects of the rule in response to several administrative reconsideration petitions. On October 15, 2018, the EPA proposed to amend the New Source Performance Standards for the Oil and Natural Gas Sector to, among other things, address fugitive emissions, pneumatic pump standards, and closed vent system certification requirements. The schedule for when this rulemaking could be finalized is not presently known. The EPA’s greenhouse gas regulations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations and also could adversely affect demand for the products that we transport, store, process, or otherwise handle in connection with our services.

Some scientists have suggested climate change from greenhouse gases could increase the severity of extreme weather, such as increased hurricanes and floods, which could damage our facilities. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our natural gas liquids is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for our products and services. If there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Because propane is considered a clean alternative fuel under the federal Clean Air Act Amendments of 1990, new climate change regulations may provide us with a competitive advantage over other sources of energy, such as fuel oil and coal.

The trend of more expansive and stringent environmental legislation and regulations, including greenhouse gas regulation, could continue, resulting in increased costs of conducting business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts certain aspects of our business or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

Safety and Transportation

All states in which we operate have adopted fire safety codes that regulate the storage and distribution of propane and distillates. In some states, state agencies administer these laws. In others, municipalities administer them. We conduct training programs to help ensure that our operations comply with applicable governmental regulations. With respect to general operations, each state in which we operate adopts National Fire Protection Association, Pamphlet Nos. 54 and 58, or comparable regulations, which establish rules and procedures governing the safe handling of propane, and Pamphlet Nos. 30, 30A, 31, 385, and 395 which establish rules and procedures governing the safe handling of distillates, such as fuel oil. We believe that the policies and procedures currently in effect at all of our facilities for the handling, storage and distribution of propane and distillates and related service and installation operations are consistent with industry standards and are in compliance in all material respects with applicable environmental, health and safety laws.

With respect to the transportation of propane, distillates, crude oil, and water, we are subject to regulations promulgated under federal legislation, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002.

Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the United States Department of Transportation ("DOT"). Specifically, crude oil pipelines are subject to regulation by the DOT, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), under the Hazardous Liquid Pipeline Safety Act of 1979 ("HLPSA"), which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the storage and transportation of hazardous liquids by and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations.

The Pipeline Safety Act of 1992 added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in high consequence areas ("HCAs"), defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, Congress required mandatory inspections for certain United States crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management. In January 2012, the federal government passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"). This act provides for additional regulatory oversight of the nation's pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. The 2011 Pipeline Safety Act increases the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 million to $2 million. In addition, this law established additional safety requirements for newly constructed pipelines. The law also provides for (i) additional pipeline damage prevention measures; (ii) allowing the Secretary of Transportation to require automatic and remote-controlled shut-off valves on new pipelines; (iii) requiring the Secretary of Transportation to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements; (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders; and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents. On June 22, 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 was enacted, further strengthening PHMSA's safety authority.

Railcar Regulation

We transport a significant portion of our natural gas liquids, crude oil, ethanol and biodiesel via rail transportation, and we own and lease a fleet of railcars for this purpose. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, as well as other federal and state regulatory agencies.

The adoption of additional federal, state or local laws or regulations, including any voluntary measures by the rail industry regarding railcar design or crude oil rail transport activities, or efforts by local communities to restrict or limit rail traffic involving crude oil, could similarly affect our business by increasing compliance costs and decreasing demand for our services, which could adversely affect our financial position and cash flows.

Occupational Health Regulations

The workplaces associated with our manufacturing, processing, terminal, storage facilities and distribution facilities are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. We believe we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. Our marine vessel operations are also subject to safety and operational standards established and monitored by the United States Coast Guard. In general, we expect to increase our expenditures relating to compliance with likely higher industry and regulatory safety standards such as those described above. However, these expenditures cannot be accurately estimated at this time, but we do not expect them to have a material adverse effect on our business.

Available Information on our Website

Our website address is http://www.nglenergypartners.com. We make available on our website, free of charge, the periodic reports that we file with or furnish to the Securities and Exchange Commission ("SEC"), as well as all amendments to these reports, as soon as reasonably practicable after such reports are filed with or furnished to the SEC. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

In addition, the SEC maintains an internet site (http://www.sec.gov) that contains reports, proxy and information statements and other information related to issuers that file electronically with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

We may not have sufficient cash to enable us to pay the minimum quarterly distribution to our unitholders following the establishment of cash reserves by our general partner and the payment of costs and expenses, including reimbursement of expenses to our general partner.

We may not have sufficient cash to enable us to pay the minimum quarterly distribution. These distributions may only be made from cash available for distribution after the preferred quarterly distribution to which our preferred units are entitled. The amount of cash we can distribute on our units principally depends on the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- weather conditions in our operating areas;
- the cost of crude oil, natural gas liquids, gasoline, diesel, ethanol, and biodiesel that we buy for resale and whether we are able to pass along cost increases to our customers;
- the volume of wastewater delivered to our processing facilities;
- disruptions in the availability of crude oil and/or natural gas liquids supply;
- our ability to renew leases for storage and railcars;
- the effectiveness of our commodity price hedging strategy;
- the level of competition from other energy providers; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution also depends on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- restrictions contained in the credit agreement (the “Credit Agreement”), the indentures governing our outstanding 7.50% senior notes due 2023, 6.125% senior notes due 2025 and 7.50% senior notes due 2026 (collectively, the “Indentures”) and other debt service requirements;
- restrictions contained in our 9.00% Class B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (“Class B Preferred Units”) and 9.625% Class C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (“Class C Preferred Units”) (collectively the “Preferred Units”) agreements;
- fluctuations in working capital needs;
- our ability to borrow funds and access capital markets;
- the amount, if any, of cash reserves established by our general partner; and
- other business risks discussed in this Annual Report that may affect our cash levels.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we realize net income.

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

Our future financial performance and growth may be limited by our ability to successfully grow organically and complete accretive acquisitions on economically acceptable terms.

Our ability to complete accretive acquisitions on economically acceptable terms may be limited by various factors, including, but not limited to:

- increased competition for attractive acquisitions;
- covenants in the Credit Agreement and Indentures that limit the amount and types of indebtedness that we may incur to finance acquisitions and which may adversely affect our ability to make distributions to our unitholders;
- lack of available cash or external capital or limitations on our ability to issue equity to pay for acquisitions; and
- possible unwillingness of prospective sellers to accept our common units as consideration and the potential dilutive effect to our existing unitholders caused by an issuance of common units in an acquisition.

There can be no assurance that we will identify attractive acquisition candidates in the future, that we will be able to acquire such businesses on economically acceptable terms, that any acquisitions will not be dilutive to earnings and distributions or that any additional debt that we incur to finance an acquisition will not adversely affect our ability to make distributions to unitholders. Furthermore, if we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We may be subject to substantial risks in connection with the integration and operation of acquired businesses, in particular those businesses with operations that are distinct and separate from our existing operations.

Any acquisitions we make in pursuit of our growth strategy are subject to potential risks, including, but not limited to:

- the inability to successfully integrate the operations of recently acquired businesses;
- the assumption of known or unknown liabilities, including environmental liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity, debt or synergies;
- mistaken assumptions about sales volume, margin or operational expenses;
- unforeseen difficulties operating in new geographic areas or in new business segments;
- the diversion of management’s and employees’ attention from other business concerns;
- customer or key employee loss from the acquired businesses; and
- a potential significant increase in our indebtedness and related interest expense.

We undertake due diligence efforts in our assessment of acquisitions, but may be unable to identify or fully plan for all issues and risks associated with a particular acquisition. Even when an issue or risk is identified, we may be unable to obtain adequate contractual protection from the seller. The realization of any of these risks could have a material adverse effect on the success of a particular acquisition or our consolidated financial position, results of operations or future growth.

As part of our growth strategy, we may expand our operations into businesses that differ from our existing operations. Integration of new businesses is a complex, costly and time-consuming process and may involve assets with which we have limited operating experience. Failure to timely and successfully integrate acquired businesses into our existing operations may have a material adverse effect on our business, consolidated financial position or results of operations. In addition to the risks set forth above, new businesses will subject us to additional business and operating risks, such as the acquisitions not being accretive to our unitholders as a result of decreased profitability, increased interest expense related to debt we incur to make such acquisitions or an inability to successfully integrate those operations into our overall business operations. The realization of any of these risks could have a material adverse effect on our consolidated financial position or results of operations.

Our substantial indebtedness may limit our flexibility to obtain financing and to pursue other business opportunities.

At March 31, 2019, the face amount of our long-term debt was $2.2 billion. Our level of debt could have important consequences to us, including the following:

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

Our ability to service our debt will depend on, among other things, our future financial and operating performance, which will be affected by prevailing economic and weather 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 future indebtedness, we would be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may be unable to effect any of these actions on satisfactory terms or at all. The agreements governing our indebtedness permit us to incur additional debt under certain circumstances, and we will likely need to incur additional debt in order to implement our growth strategy. We may experience adverse consequences from increased levels of debt.

Restrictions in the Credit Agreement and Indentures could adversely affect our business, financial position, results of operations, ability to make distributions to unitholders and the value of our common units.

The Credit Agreement and Indentures limit our ability to, among other things:

- incur additional debt or issue letters of credit;
- redeem or repurchase units;
- make certain loans, investments and acquisitions;
- incur certain liens or permit them to exist;
- engage in sale and leaseback transactions;
- enter into certain types of transactions with affiliates;
- enter into agreements limiting subsidiary distributions;
- change the nature of our business or enter into a substantially different business;
- merge or consolidate with another company; and
- transfer or otherwise dispose of assets.

We are permitted to make distributions to our unitholders under the Credit Agreement and Indentures as long as no default or event of default exists both immediately before and after giving effect to the declaration and payment of the distribution and the distribution does not exceed available cash for the applicable quarterly period. The Credit Agreement and Indentures also contain covenants requiring us to maintain certain financial ratios. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

The provisions of the Credit Agreement and Indentures may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of the Credit Agreement could result in a covenant violation, default or an event of default that could enable our lenders, subject to the terms and conditions of the Credit Agreement, to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, our lenders could proceed against the collateral we granted them to secure our debts. If the payment of our debt is accelerated, defaults under our other debt instruments, if any then exist, may be triggered, and our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Increases in interest rates could adversely impact our common 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.

Interest rates may increase in the future. As a result, interest rates on our existing and future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our common unit price will be impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our common unit price and our ability to issue equity or incur debt for acquisitions or other purposes and to make payments on our debt obligations and cash distributions at our intended levels.

Our business depends on the availability of crude oil, natural gas liquids, and refined products in the United States and Canada, which is dependent on the ability and willingness of other parties to explore for and produce crude oil and natural gas. Spending on crude oil and natural gas exploration and production may be adversely affected by industry and financial market conditions that are beyond our control.

Our business depends on domestic spending by the oil and natural gas industry, and this spending and our business have been, and may continue to be, adversely affected by industry and financial market conditions and existing or new regulations, such as those related to environmental matters, that are beyond our control.

We depend on the ability and willingness of other entities to make operating and capital expenditures to explore for, develop, and produce crude oil and natural gas in the United States and Canada, and to extract natural gas liquids from natural gas as well as the availability of necessary pipeline transportation and storage capacity. Customers’ expectations of lower market prices for crude oil and natural gas, as well as the availability of capital for operating and capital expenditures, may cause them to curtail spending, thereby reducing business opportunities and demand for our services and equipment. Actual market conditions and producers’ expectations of market conditions for crude oil and natural gas liquids may also cause producers to curtail spending, thereby reducing business opportunities and demand for our services.

Industry conditions are influenced by numerous factors over which we have no control, such as the availability of commercially viable geographic areas in which to explore and produce crude oil and natural gas, the availability of liquids-rich natural gas needed to produce natural gas liquids, the supply of and demand for crude oil and natural gas, environmental restrictions on the exploration and production of crude oil and natural gas, such as existing and proposed regulation of hydraulic fracturing, domestic and worldwide economic conditions, political instability in crude oil and natural gas producing countries and merger and divestiture activity among our current or potential customers. The volatility of the oil and natural gas industry and the resulting impact on exploration and production activity could adversely impact the level of drilling activity. This reduction may cause a decline in business opportunities or the demand for our services, or adversely affect the price of our services. Reduced discovery rates of new crude oil and natural gas reserves in our market areas also may have a negative long-term impact on our business, even in an environment of stronger crude oil and natural gas prices, to the extent existing production is not replaced.

The crude oil and natural gas production industry tends to run in cycles and may, at any time, cycle into a downturn; if that occurs, the rate at which it returns to former levels, if ever, will be uncertain. Prior adverse changes in the global economic environment and capital markets and declines in prices for crude oil and natural gas have caused many customers to reduce capital budgets for future periods and have caused decreased demand for crude oil and natural gas. Limitations on the availability of capital, or higher costs of capital, for financing expenditures have caused and may continue to cause customers to make additional reductions to capital budgets in the future even if commodity prices increase from current levels. These cuts in spending may curtail drilling programs and other discretionary spending, which could result in a reduction in business opportunities and demand for our services, the rates we can charge and our utilization. In addition, certain of our customers could become unable to pay their suppliers, including us. Any of these conditions or events could materially and adversely affect our consolidated results of operations.

Declining crude oil prices could adversely impact our Water Solutions and Crude Oil Logistics businesses.

Crude oil spot and forward prices experienced a sharp decline during the second half of calendar year 2014. While crude oil prices have rebounded from the lows experienced during the first three months of calendar year 2016, they are still well below the prices from the first half of calendar year 2014. This has had an unfavorable impact on the revenues of our Water Solutions business. The volume of water we process is driven in part by the level of crude oil production, and the lower crude oil prices have given producers less incentive to expand production. In addition, a portion of the revenues in our Water

Solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater , and lower crude oil prices have an adverse impact on these revenues. A further decline in crude oil prices or a prolonged period of low crude oil prices could have an adverse effect on our Water Solutions business.

In addition, the sharp decline in crude oil prices has reduced the incentive for producers to expand production. If crude oil prices remain low, resultant declines in crude oil production could adversely impact volumes in our Crude Oil Logistics business.

Our profitability could be negatively impacted by price and inventory risk related to our business.

The Crude Oil Logistics, Liquids, and Refined Products and Renewables businesses are "margin-based" businesses in which our realized margins depend on the differential of sales prices over our total supply costs. Our profitability is therefore sensitive to changes in product prices caused by changes in supply, pipeline transportation and storage capacity or other market conditions.

Generally, we attempt to maintain an inventory position that is substantially balanced between our purchases and sales, including our future delivery obligations. We attempt to obtain a certain margin for our purchases by selling our product to our customers, which include third-party consumers, other wholesalers and retailers, and others. However, market, weather or other conditions beyond our control may disrupt our expected supply of product, and we may be required to obtain supply at increased prices that cannot be passed through to our customers. In general, product supply contracts permit suppliers to charge posted prices at the time of delivery or the current prices established at major storage points, creating the potential for sudden and drastic price fluctuations. Sudden and extended wholesale price increases could reduce our margins. Conversely, a prolonged decline in product prices could potentially result in a reduction of the borrowing base under our working capital facility, and we could be required to liquidate inventory that we have already presold.

One of the strategies of our Refined Products and Renewables segment is to purchase refined products in the Gulf Coast region and to transport the product on the Colonial pipeline for sale in the Southeast and East Coast. Spreads between product prices in the Gulf Coast compared to locations along the Colonial pipeline can vary significantly, which can create volatility in our product margins. In addition, we are subject to the risk of a price decline between the time we purchase refined products and the time we sell the products. We seek to mitigate this risk by entering into NYMEX futures contracts. However, price changes in locations where we operate do not correspond directly with changes in prices in the NYMEX futures market, and as a result these futures contracts cannot be perfect hedges of our commodity price risk.

We are affected by competition from other midstream, transportation, and terminaling and storage companies, some of which are larger and more firmly established and may have greater resources than we do.

We experience competition in all of our segments. In our Liquids segment, we compete for natural gas liquids supplies and also for customers for our services. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas. Our natural gas liquids terminals compete with other terminaling and storage providers in the transportation and storage of natural gas liquids. Natural gas and natural gas liquids also compete with other forms of energy, including electricity, coal, fuel oil and renewable or alternative energy.

Our Crude Oil Logistics segment faces significant competition for crude oil supplies and also for customers for our services. These operations also face competition from trucking companies for incremental and marginal volumes in the areas we serve. Further, our crude oil terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

Our Water Solutions segment is in direct and indirect competition with other businesses, including disposal and other wastewater treatment businesses.

Our Refined Products and Renewables segment also faces significant competition for refined products and renewables supplies and also for customers for our services.

We can make no assurance that we will compete successfully in each of our lines of business. If a competitor attempts to increase market share by reducing prices, we may lose customers, which would reduce our revenues.

Our business would be adversely affected if service at our principal storage facilities or on the common carrier pipelines or railroads we use is interrupted.

We use third-party common carrier pipelines to transport our products and we use third-party facilities to store our products. Any significant interruption in the service at these storage facilities or on the common carrier pipelines we use would adversely affect our ability to obtain products. We transport crude oil, natural gas liquids, ethanol, and biodiesel by railcar. We do not own or operate the railroads on which these railcars are transported. Any disruptions in the operations of these railroads could adversely impact our ability to deliver product to our customers.

The fees charged to customers under our agreements with them for the transportation and marketing of crude oil, condensate, natural gas liquids, gasoline, diesel, ethanol, and biodiesel may not escalate sufficiently to cover increases in costs and the agreements may be suspended in some circumstances, which would affect our profitability.

Our costs may increase more rapidly than the fees that we charge to customers pursuant to our contracts with them. Additionally, some customers' obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure events wherein the supply of crude oil, condensate, and/or natural gas liquids are curtailed or cut off. Force majeure events include (but are not limited to) revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions, mechanical or physical failures of our equipment or facilities of our customers. If the escalation of fees is insufficient to cover increased costs, or if any customer suspends or terminates its contracts with us, our profitability could be materially and adversely affected.

Our sales of crude oil, condensate, natural gas liquids, gasoline, diesel, ethanol, and biodiesel and related transportation and hedging activities, and our processing of wastewater, expose us to potential regulatory risks.

The FTC, the FERC, and the CFTC hold statutory authority to monitor certain segments of the physical and financial energy commodity markets. With regard to our physical sales of energy commodities, and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, some of our operations are currently subject to the FERC regulations obligating us to comply with the FERC's regulations and policies applicable to those assets and operations. Other of our operations may become subject to the FERC's jurisdiction in the future (see *"–Some of our operations are subject to the jurisdiction of the FERC and other operations may become subject in the future,"* below). Any failure on our part to comply with the FERC's regulations and policies at that time could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material and adverse effect on our business, consolidated results of operations and financial position.

The intrastate transportation or storage of crude oil and refined products is subject to regulation by the state in which the facilities are located and transactions occur. Compliance with these state regulations could have a material and adverse effect on that portion of our business, consolidated results of operations and financial position.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for statutory and regulatory requirements for derivative transactions, including crude oil, refined and renewable products, and natural gas hedging transactions. Certain transactions will be required to be cleared on exchanges and cash collateral will have to be posted. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end users and it includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and the parties to those transactions. Since the Dodd-Frank Act mandates the CFTC to promulgate rules to define these terms, the full impact of the Dodd-Frank Act on our hedging activities is uncertain at this time. However, new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Dodd-Frank Act may also materially affect our customers and materially and adversely affect the demand for our services.

We are subject to trucking safety regulations, which are enacted, reviewed and amended by the Federal Motor Carrier Safety Administration ("FMCSA"). If our current DOT safety ratings are downgraded to "Unsatisfactory", our business and results of our operations may be adversely affected.

All federally regulated carriers' safety ratings are measured through a program implemented by the FMCSA known as the Compliance Safety Accountability ("CSA") program. The CSA program measures a carrier's safety performance based on violations observed during roadside inspections as opposed to compliance audits performed by the FMCSA. The quantity and severity of any violations are compared to a peer group of companies of comparable size and annual mileage. If a company rises above a threshold established by the FMCSA, it is subject to action from the FMCSA. There is a progressive intervention strategy that begins with a company providing the FMCSA with an acceptable plan of corrective action that the company will implement. If the issues are not corrected, the intervention escalates to on-site compliance audits and ultimately an "unsatisfactory" rating and the revocation of the company's operating authority by the FMCSA, which could result in a material adverse effect on our business, consolidated results of operations and financial position and ability to make cash distributions to our unitholders.

Our business is subject to federal, state, provincial and local laws and regulations with respect to environmental, safety and other regulatory matters and the cost of compliance with, violation of or liabilities under, such laws and regulations could adversely affect our profitability.

Our operations, including those involving crude oil, condensate, natural gas liquids, refined products, renewables, and crude oil and natural gas produced wastewater, are subject to stringent federal, state, provincial and local laws and regulations relating to the protection of natural resources and the environment, health and safety, waste management, and transportation and disposal of such products and materials. We face inherent risks of incurring significant environmental costs and liabilities due to handling of wastewater and hydrocarbons, such as crude oil, condensate, natural gas liquids, gasoline, diesel, ethanol, and biodiesel. For instance, our Water Solutions business carries with it environmental risks, including leakage from the treatment plants to surface or subsurface soils, surface water or groundwater, or accidental spills. Our Crude Oil Logistics, Liquids, and Refined Products and Renewables businesses carry similar risks of leakage and sudden or accidental spills of crude oil, natural gas liquids, and hydrocarbons. Liability under, or violation of, environmental laws and regulations could result in, among other things, the impairment or cancellation of operations, injunctions, fines and penalties, reputational damage, expenditures for remediation and liability for natural resource damages, property damage and personal injuries.

We use various modes of transportation to carry natural gas liquids, crude oil, refined and renewable products and water, including trucks, railcars, barges, and pipelines, each of which is subject to regulation. With respect to transportation by truck, we are subject to regulations promulgated under federal legislation, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002, which cover the security and transportation of hazardous materials and are administered by the DOT. We also own and lease a fleet of railcars, the operation of which is subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, as well as other federal and state regulatory agencies. Railcar accidents within the industry involving trains carrying crude oil from the Bakken region (none of which directly involved any of our business operations), have led to increased legislative and regulatory scrutiny over the safety of transporting crude oil by railcar. The introduction of regulations that result in new requirements addressing the type, design, specifications or construction of railcars used to transport crude oil could result in severe transportation capacity constraints during the periods in which new railcars are constructed to meet new specifications or in which the railcars already placed in service are being retrofitted. Our barge transportation operations are subject to the Jones Act, a federal law generally restricting marine transportation in the United States to vessels built and registered in the United States, and manned/owned by United States citizens, as well as setting forth the rules and regulations of the United States Coast Guard. Non-compliance with any of these regulations could result in increased costs related to the transportation of our products and could have an adverse effect on our business.

In addition, under certain environmental laws, we could be subject to strict and/or joint and several liability for the investigation, removal or remediation of previously released materials. As a result, these laws could cause us to become liable for the conduct of others, such as prior owners or operators of our facilities, or for consequences of our or our predecessor's actions, regardless of whether we were responsible for the release or if such actions were in compliance with all applicable laws at the time of those actions. Also, upon closure of certain facilities, such as at the end of their useful life, we have been and may be required to undertake environmental evaluations or cleanups.

Additionally, in order to conduct our operations, we must obtain and maintain numerous permits, approvals and other authorizations from various federal, state, provincial and local governmental authorities relating to wastewater handling, discharge and disposal, air emissions, transportation and other environmental matters. These authorizations subject us to terms and conditions which may be onerous or costly to comply with, and that may require costly operational modifications to attain and maintain compliance. The renewal, amendment or modification of these permits, approvals and other authorizations may involve the imposition of even more stringent and burdensome terms and conditions with attendant higher costs and more significant effects upon our operations.

Changes in environmental laws and regulations occur frequently. New laws or regulations, changes to existing laws or regulations, such as more stringent pollution control requirements or additional safety requirements, or more stringent interpretation or enforcement of existing laws and regulations, may adversely impact us, and could result in increased operating costs and have a material and adverse effect on our activities and profitability. For example, new or proposed laws or regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our costs for treatment of hydraulic fracturing flowback water (or affect our hydraulic fracturing customers' ability to operate) and cause delays, interruption or termination of our water treatment operations, all of which could have a material and adverse effect on our consolidated results of operations and financial position.

Furthermore, our customers in the oil and gas production industry are subject to certain environmental laws and regulations that may impose significant costs and liabilities on them. Any significant increased costs or restrictions placed on our customers to comply with environmental laws and regulations could affect their production output significantly. Such an effect on our customers could materially and adversely affect our utilization and profitability by reducing demand for our services. The adoption or implementation of any new regulations imposing additional reporting obligations on greenhouse gas emissions, or limiting greenhouse gas emissions from our equipment and operations, could require us to incur significant costs.

State legislation and regulatory initiatives relating to our hydraulic fracturing customers could harm our business.

Hydraulic fracturing is a frequent practice in the crude oil and natural gas fields in which our Water Solutions segment operates. Hydraulic fracturing is an important and common process used to facilitate production of natural gas and other hydrocarbon condensates in shale formations, as well as tight conventional formations. The hydraulic fracturing process is primarily regulated by state oil and gas authorities. This process has come under considerable scrutiny from sections of the public as well as environmental and other groups asserting that chemicals used in the hydraulic fracturing process could adversely affect drinking water supplies. New laws or regulations, or changes to existing laws or regulations in response to this perceived threat may adversely impact the oil and gas drilling industry. Any current or proposed restrictions on hydraulic fracturing could lead to operational delays or increased operating costs and regulatory burdens that could make it more difficult or costly to perform hydraulic fracturing which would negatively impact our customer base resulting in an adverse effect on our profitability.

Federal and state legislation and regulatory initiatives relating to saltwater disposal wells could result in increased costs and additional operating restrictions or delays and could harm our business.

The water disposal process is primarily regulated by state oil and gas authorities. This water disposal process has come under scrutiny from sections of the public as well as environmental and other groups asserting that the operation of certain water disposal wells has caused increased seismic activity. New laws or regulations, or changes to existing laws or regulations, in response to this perceived threat may adversely impact the water disposal industry.

On certain occasions, a state regulatory agency has requested that we suspend operations at a specified disposal facility, pending further study of its potential impact on seismic activity. In one instance we have modified a disposal well to redirect the flow of water to a different area of the geologic formation in order to address such concerns.

We cannot predict whether any federal, state or local laws or regulations will be enacted and, if so, what actions any such laws or regulations would require or prohibit. However, any restrictions on water disposal could lead to operational delays or increased operating costs and regulatory burdens that could make it more difficult or costly to perform water disposal operations, which would negatively impact our profitability.

Seasonal weather conditions and natural or man-made disasters could severely disrupt normal operations and have an adverse effect on our business, financial position and results of operations.

We operate in various locations across the United States and Canada which may be adversely affected by seasonal weather conditions and natural or man-made disasters. During periods of heavy snow, ice, rain or extreme weather conditions such as high winds, tornados and hurricanes or after other natural disasters such as earthquakes or wildfires, we may be unable to move our trucks or railcars between locations and our facilities may be damaged, thereby reducing our ability to provide services and generate revenues. In addition, hurricanes or other severe weather in the Gulf Coast region could seriously disrupt the supply of products and cause serious shortages in various areas, including the areas in which we operate. These same conditions may cause serious damage or destruction to homes, business structures and the operations of customers. Such disruptions could potentially have a material adverse impact on our business, consolidated financial position, results of operations and cash flows.

Risk management procedures cannot eliminate all commodity risk, basis risk, or risk of adverse market conditions which can adversely affect our financial position and results of operations. In addition, any non-compliance with our risk policy could result in significant financial losses.

Pursuant to the requirements of our market risk policy, we attempt to lock in a margin for a portion of the commodities we purchase by selling such commodities for physical delivery to our customers, such as independent refiners or major oil companies, or by entering into future delivery obligations under contracts for forward sale. We also enter into financial derivative contracts, such as futures, to manage commodity price risk. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. These policies and practices cannot, however, eliminate all risks. For example, any event that disrupts our anticipated physical supply of commodities could expose us to risk of loss resulting from the need to cover obligations required under contracts for forward sale. Additionally, we can provide no assurance that our processes and procedures will detect and/or prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Basis risk describes the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of a like commodity at a different time or place. Transportation costs and timing differentials are components of basis risk. In a backwardated market (when prices for future deliveries are lower than current prices), basis risk is created with respect to timing. In these instances, physical inventory generally loses value as the price of such physical inventory declines over time. Basis risk cannot be entirely eliminated, and basis exposure, particularly in backwardated or other adverse market conditions, can adversely affect our consolidated financial position and results of operations.

The counterparties to our commodity derivative and physical purchase and sale contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

We encounter risk of counterparty nonperformance in our businesses. Disruptions in the supply of product and in the crude oil and natural gas commodities sector overall for an extended or near term period of time could result in counterparty defaults on our derivative and physical purchase and sale contracts. This could impair our ability to obtain supply to fulfill our sales delivery commitments or obtain supply at reasonable prices, which could result in decreased gross margins and profitability, thereby impairing our ability to make payments on our debt obligations or distributions to our unitholders.

Our use of derivative financial instruments could have an adverse effect on our results of operations.

We have used derivative financial instruments as a means to protect against commodity price risk or interest rate risk and expect to continue to do so. We may, as a component of our overall business strategy, increase or decrease from time to time our use of such derivative financial instruments in the future. Our use of such derivative financial instruments could cause us to forego the economic benefits we would otherwise realize if commodity prices or interest rates were to change in our favor. In addition, although we monitor such activities in our risk management processes and procedures, such activities could result in losses, which could adversely affect our consolidated results of operations and impair our ability to make payments on our debt obligations or distributions to our unitholders.

Some of our operations are subject to the jurisdiction of the FERC and other operations may become subject in the future .

The FERC regulates the transportation of crude oil and refined products on interstate pipelines, among other things. Intrastate transportation and gathering pipelines that do not provide interstate services are not subject to regulation by the FERC. The distinction between the FERC-regulated interstate pipeline transportation on the one hand and intrastate pipeline transportation on the other hand, is a fact-based determination. The Grand Mesa Pipeline became operational on November 1, 2016 and has several points of origin in Colorado, runs from those origin points through Kansas and terminates in Cushing, Oklahoma. The transportation services on the Grand Mesa Pipeline are subject to FERC regulation. Other of our transportation services could in the future become subject to the jurisdiction of the FERC, which could adversely affect the terms of service, rates and revenues of such services.

The classification and regulation of our crude oil pipelines are subject to change based on future determinations by the FERC, federal courts, Congress or regulatory commissions, courts or legislatures in the states in which we operate. If the FERC’s regulatory reach was expanded to our other facilities, or if we expand our operations into areas that are subject to the FERC’s regulation, we may have to commit substantial capital to comply with such regulations and such expenditures could have a material and adverse effect on our consolidated results of operations and cash flows.

Volumes of hydrocarbons recovered during the wastewater treatment process can vary. Any significant reduction in residual crude oil content in wastewater we treat will affect our recovery of hydrocarbons and, therefore, our profitability.

A portion of the revenues in our Water Solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater. Our ability to recover sufficient volumes of hydrocarbons is dependent upon the residual crude oil content in the wastewater we treat, which is, among other things, a function of water temperature. Generally, where water temperature is higher, residual crude oil content is lower. Thus, our crude oil recovery during the winter season is substantially higher than our recovery during the summer season. Additionally, residual crude oil content will decrease if, among other things, producers begin recovering higher levels of crude oil in produced wastewater prior to delivering such water to us for treatment. Any reduction in residual crude oil content in the wastewater we treat could materially and adversely affect our profitability.

Competition from alternative energy sources may cause us to lose customers, thereby negatively impacting our financial position and results of operations.

Propane competes with other sources of energy, some of which are less costly for equivalent energy value. We compete for customers against suppliers of electricity, natural gas and fuel oil. Competition from alternative energy sources, including electricity, natural gas and renewables, has increased as a result of reduced regulation of many utilities. Electricity is a major competitor of propane, but propane in some regions has historically had a competitive price advantage over electricity. Except for some industrial and commercial applications, propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because such pipelines generally make it possible for the delivered cost of natural gas to be less expensive than the bulk delivery of propane. The expansion of natural gas into traditional propane markets has historically been inhibited by the capital cost required to expand distribution and pipeline systems; however, the gradual expansion of the nation’s natural gas distribution systems has resulted in natural gas being available in areas that previously depended on propane, which could cause us to lose customers, thereby reducing our revenues. Although propane is similar to fuel oil in some applications and market demand, propane and fuel oil compete to a lesser extent primarily because of the cost of converting from one to the other.

We cannot predict the effect that development of alternative energy sources may have on our operations, including whether subsidies of alternative energy sources by local, state, and federal governments might be expanded, or what impact this might have on the supply of or the demand for crude oil, natural gas, and natural gas liquids.

Energy efficiency and new technology may reduce the demand for propane and adversely affect our operating results.

The national trend toward increased conservation and technological advances, such as installation of improved insulation and the development of more efficient furnaces and other appliances, has adversely affected the demand for propane and distillates by retail customers. Future conservation measures or technological advances in appliance efficiency, power generation or other devices may reduce demand for propane. In addition, if the price of propane increases, some of our customers may increase their conservation efforts and thereby decrease their consumption of propane.

Reduced demand for refined products could have an adverse effect our results of operations.

Any sustained decrease in demand for refined products in the markets we serve could reduce our cash flow. Factors that could lead to a decrease in market demand include:

- a recession or other adverse economic condition that results in lower spending by consumers on gasoline, diesel, and travel;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline;
- an increase in automotive engine fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles or technological advances by manufacturers;
- an increase in the market price of crude oil that leads to higher refined product prices, which may reduce demand for refined products and drive demand for alternative products; and
- the increased use of alternative fuel sources, such as battery-powered engines.

Recent attempts to reduce or eliminate the federal Renewable Fuels Standard ("RFS"), if successful, could adversely impact our results of operations.

The United States renewables industry is highly dependent on several federal and state incentives which promote the use of renewable fuels. Without these incentives, demand for and the price of renewable fuels could be negatively impacted which could have an adverse effect on our consolidated results of operations. The most significant of the federal and state incentives which benefit renewable products we market, such as ethanol and biodiesel, is the RFS. The RFS requires that an increasing amount of renewable fuels must be blended with petroleum-based fuels each year in the United States. However, the EPA has authority to waive the requirements of the RFS, in whole or in part, if certain conditions are met. Opponents of the RFS have sought, and may continue to seek, to force the EPA to reduce or eliminate the RFS. Further, legislation has been introduced with the goal of significantly reducing or eliminating the RFS. While the outcome of these legislative efforts is uncertain, it is possible that the EPA could adjust the RFS requirements in the future. If the EPA were to adjust the RFS requirements in any material way, it could negatively impact demand for the renewable fuel products we market, which could adversely impact our consolidated results of operations.

The expiration of tax credits could adversely impact the demand for biodiesel, which could adversely impact our results of operations.

The demand for biodiesel is supported by certain federal tax credits. These tax credits have typically been granted for short durations, and on several occasions these tax credits have expired. In February 2018, the federal government passed a law to reinstate the tax credit retroactively to January 1, 2017, with the credit expiring on December 31, 2017. Legislation is pending in Congress (e.g., H.R. 2089 proposed by Representative Abby Finkenauer (D-IA) and S. 1288 proposed by Senator Ron Wyden (D-OR) that would, if passed and signed into law, further extend these tax credits. There can be no assurance that the federal government will grant such tax credits in the future. If the federal government were to discontinue the practice of granting such tax credits, this would likely have an adverse effect on demand for biodiesel and on our biodiesel marketing operations.

A loss of one or more significant customers could materially or adversely affect our results of operations.

We expect to continue to depend on key customers to support our revenues for the foreseeable future. The loss of key customers, failure to renew contracts upon expiration, or a sustained decrease in demand by key customers could result in a substantial loss of revenues and could have a material and adverse effect on our consolidated results of operations. During the year ended March 31, 2019, a significant portion of our revenues was dependent on key customers as summarized below:

- 79% of the revenues of our Crude Oil Logistics segment were generated from our ten largest customers of the segment ;
- 48% of the water treatment and disposal revenues of our Water Solutions segment were generated from our ten largest customers of the segment;
- 27% of the revenues of our Liquids segment were generated from our ten largest customers of the segment); and
- 40% of the revenues of our Refined Products and Renewables segment were generated from our ten largest customers of the segment.

Certain of our operations are conducted through joint ventures which have unique risks.

Certain of our operations are conducted through joint ventures. With respect to our joint ventures, we share ownership and management responsibilities with partners that may not share our goals and objectives. Differences in views among the partners may result in delayed decisions or failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the joint venture. Accordingly, delayed decisions and disagreements could adversely affect the business and operations of the joint ventures and, in turn, our business and operations. From time to time, our joint ventures may be involved in disputes or legal proceedings which may negatively affect our investments. Accordingly, any such occurrences could adversely affect our consolidated results of operations, financial position and cash flows.

Growing our business by constructing new transportation systems and facilities subjects us to construction risks and risks that supplies for such systems and facilities will not be available upon completion thereof.

One of the ways we intend to grow our business is through the construction of additions to our systems and/or the construction of new terminaling, transportation, and wastewater treatment facilities. These expansion projects require the expenditure of significant amounts of capital, which may exceed our resources, and involve numerous regulatory, environmental, political and legal uncertainties, including political opposition by landowners, environmental activists and others. There can be no assurance that we will complete these projects on schedule or at all or at the budgeted cost. Our revenues may not increase upon the expenditure of funds on a particular project. Moreover, we may undertake expansion projects to capture anticipated future growth in production in a region in which anticipated production growth does not materialize or for which we are unable to acquire new customers. We may also rely on estimates of proved, probable or possible reserves in our decision to undertake expansion projects, which may prove to be inaccurate. As a result, our new facilities and infrastructure may not be able to attract enough product to achieve our expected investment return, which could materially and adversely affect our consolidated results of operations and financial position.

We may face opposition to the operation of our pipelines and facilities from various groups.

We may face opposition to the operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

Product liability claims and litigation could adversely affect our business and results of operations.

Our operations are subject to all operating hazards and risks incident to handling, storing, transporting and providing customers with combustible liquids. As a result, we are subject to product liability claims and litigation, including potential class actions, in the ordinary course of business. Any product liability claim brought against us, with or without merit, could be costly to defend and could result in an increase of our insurance premiums. Some claims brought against us might not be covered by our insurance policies. In addition, we have self-insured retention amounts which we would have to pay in full before obtaining any insurance proceeds to satisfy a judgment or settlement and we may have insufficient reserves on our balance sheet to satisfy such self-retention obligations. Furthermore, even where the claim is covered by our insurance, our insurance coverage might be inadequate and we would have to pay the amount of any settlement or judgment that is in excess of our policy limits. Our failure to maintain adequate insurance coverage or successfully defend against product liability claims could materially and adversely affect our business, consolidated results of operations, financial position and cash flows.

A failure in our operational systems or cyber security 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 or operational systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our systems. In addition, dependence upon automated systems may further increase the risk related to operational system flaws, and 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 increase efficiency in our business. We use various systems in our financial and operations sectors, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber attacks on our customer and employee data may result in a financial loss, including potential fines for failure to safeguard data, and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, resulting in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

We lease certain facilities and equipment and therefore are subject to the possibility of increased costs to retain necessary land and equipment use.

We do not own all of the land on which our facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if our facilities are not properly located within the boundaries of such rights-of-way. Additionally, our loss of rights, through our inability to renew right-of-way contracts or otherwise, could materially and adversely affect our business, consolidated results of operations and financial position.

Additionally, certain facilities and equipment (or parts thereof) used by us are leased from third parties for specific periods, including many of our railcars. Our inability to renew facility or equipment leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material and adverse effect on our consolidated results of operations and cash flows.

Difficulty in attracting and retaining qualified drivers could adversely affect our growth and profitability.

Maintaining a staff of qualified truck drivers is critical to the success of our crude oil logistics operations. We have in the past experienced difficulty in attracting and retaining sufficient numbers of qualified drivers. Regulatory requirements, including the FMCSA's CSA initiative, and an improvement in the economy could reduce the number of eligible drivers or require us to pay more to attract and retain drivers. A shortage of qualified drivers and intense competition for drivers from other companies would create difficulties in increasing the number of our drivers in the event we choose to expand our fleet of trucks. If we are unable to continue to attract and retain a sufficient number of qualified drivers, we could have difficulty meeting customer demands, which could materially and adversely affect our growth and profitability.

If we fail to maintain an effective system of internal control, including internal control over financial reporting, we may be unable to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended. We are also subject to the obligation under Section 404(a) of the Sarbanes Oxley Act of 2002 to annually review and report on our internal control over financial reporting, and to the obligation under Section 404(b) of the Sarbanes Oxley Act of 2002 to engage our independent registered public accounting firm to attest to the effectiveness of our internal control over financial reporting.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud, and operate successfully as a publicly traded partnership. Our efforts to maintain our internal controls may be unsuccessful, and we may be unable to maintain effective internal control over financial reporting, including our disclosure controls. Any failure to maintain effective internal control over financial reporting and disclosure controls could harm our operating results or cause us to fail to meet our reporting obligations. These risks may be heightened after a business combination, during the phase when we are implementing our internal control structure over the recently acquired business.

Given the difficulties inherent in the design and operation of internal control over financial reporting, as well as future growth of our businesses, we can provide no assurance as to either our or our independent registered public accounting firm's conclusions about the effectiveness of internal controls in the future, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls could subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the market price of our common units.

An impairment of goodwill and long-lived assets could reduce our earnings.

At March 31, 2019, we had goodwill and long-lived assets of $3.9 billion. Such assets are subject to impairment reviews on an annual basis, or at an interim date if information indicates that such asset values have been impaired. Any impairment we would be required to record in our financial statements would result in a charge to our income, which would reduce our earnings.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

Our credit management procedures may not fully eliminate the risk of nonpayment by our customers. We manage our credit risk exposure through credit analysis, credit approvals, establishing credit limits, requiring prepayments (partially or wholly), requiring product deliveries over defined time periods, and credit monitoring. While we believe our procedures are effective, we can provide no assurance that bad debt write-offs in the future may not be significant and any such nonpayment problems could impact our consolidated results of operations and potentially limit our ability to make payments on our debt obligations or distributions to our unitholders.

Our terminaling operations depend on various forms of transportation for receipt and delivery of crude oil, natural gas liquids and refined products.

We own natural gas liquids, crude oil and refined products terminals and lease refined products terminals. The facilities depend on pipelines, railroads, truck transports, and storage systems that are owned and operated by third parties. Any interruption of service on pipeline, railroad or lateral connections or adverse change in the terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport product to and from our facilities and have a corresponding material adverse effect on our revenues. In addition, the rates charged by the interconnected pipelines for transportation to and from our facilities impact the utilization and value of our terminals. We have historically been able to pass through the costs of pipeline transportation to our customers. However, if competing pipelines do not have similar annual tariff increases or service fee adjustments, such increases could affect our ability to compete, thereby adversely affecting our revenues.

Our marketing operations depend on the availability of transportation and storage capacity.

Our product supply is transported and stored in facilities owned and operated by third parties. Any interruption of service on the pipeline or storage companies or adverse change in the terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport products and have a corresponding material adverse effect on our revenues. In addition, the rates charged by the interconnected pipelines for transportation affects the profitability of our operations.

The financial results of our natural gas liquids businesses are seasonal and generally lower in the first and second quarters of our fiscal year, which may require us to borrow money to make distributions to our unitholders during these quarters.

The natural gas liquids inventory we have presold to customers is highest during summer months, and our cash receipts are lowest during summer months. As a result, our cash available for distribution for the summer is much lower than for the winter. With lower cash flow during the first and second fiscal quarters, we may be required to borrow money to pay distributions to our unitholders during these quarters. Any restrictions on our ability to borrow money could restrict our ability to pay the minimum quarterly distributions to our unitholders.

A significant increase in fuel prices may adversely affect our transportation costs.

Fuel is a significant operating expense for us in connection with the delivery of products to our customers. A significant increase in fuel prices will result in increased transportation costs to us. The price and supply of fuel is unpredictable and fluctuates based on events we cannot control, such as geopolitical developments, supply and demand for oil and gas, actions by oil and gas producers, war and unrest in oil producing countries and regions, regional production patterns and weather concerns. As a result, any increases in these prices may adversely affect our profitability and competitiveness.

Some of our operations cross the United States/Canada border and are subject to cross-border regulation.

Our cross-border activities subject us to regulatory matters, including import and export licenses, tariffs, Canadian and United States customs and tax issues, and toxic substance certifications. Such regulations include the “Short Supply Controls” of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these licensing, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties.

The risk of terrorism and political unrest in various energy producing regions may adversely affect the economy and the price and availability of products.

An act of terror in any of the major energy producing regions of the world could potentially result in disruptions in the supply of crude oil and natural gas, which could have a material impact on both availability and price. Terrorist attacks in the areas of our operations could negatively impact our ability to transport propane to our locations. These risks could potentially negatively impact our consolidated results of operations.

We depend on the leadership and involvement of key personnel for the success of our businesses.

We have certain key individuals in our senior management who we believe are critical to the success of our business. The loss of leadership and involvement of those key management personnel could potentially have a material adverse impact on our business and possibly on the market value of our common units.

Risks Inherent in an Investment in Us

Our partnership agreement limits the fiduciary duties of our general partner to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise be breaches of fiduciary duty.

Fiduciary duties owed to our unitholders by our general partner are prescribed by law and our partnership agreement. The Delaware Revised Uniform Limited Partnership Act ("Delaware LP Act") provides that Delaware limited partnerships may, in their partnership agreements, restrict the fiduciary duties owed by the general partner to limited partners and the partnership. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- limits the liability and reduces the fiduciary duties of our general partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing common units, our unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;
- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns and its determination whether or not to consent to any merger or consolidation of the Partnership;
- provides that our general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning our general partner subjectively believed that the decision was in, or not opposed to, the best interests of the Partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee and not involving a vote of our unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

By purchasing a common unit, a common unitholder will become bound by the provisions of our partnership agreement, including the provisions described above.

Our general partner and its affiliates have conflicts of interest with us and limited fiduciary duties to our unitholders, and they may favor their own interests to the detriment of us and our unitholders.

The NGL Energy GP Investor Group owns and controls our general partner and its 0.1% general partner interest in us. Although our general partner has certain fiduciary duties to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners. Furthermore, since certain executive officers and directors of our general partner are executive officers or directors of affiliates of our general partner, conflicts of interest may arise between the NGL Energy GP Investor Group and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders (see "–*Our partnership agreement limits the fiduciary duties of our general partner to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise be breaches of fiduciary duty*," above). The risk to our unitholders due to such conflicts may arise because of the following factors, among others:

- our general partner is allowed to take into account the interests of parties other than us, such as members of the NGL Energy GP Investor Group, in resolving conflicts of interest;
- neither our partnership agreement nor any other agreement requires owners of our general partner to pursue a business strategy that favors us;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- 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;
- our general partner determines which costs incurred by it are reimbursable by us;
- our general partner may cause us to borrow funds to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our partnership agreement permits us to classify up to $20.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the incentive distribution rights ("IDRs");
- 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; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's IDRs without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

In addition, certain members of the NGL Energy GP Investor Group and their affiliates currently hold interests in other companies in the energy and natural resource sectors. Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership interest in us. However, members of the NGL Energy GP Investor Group are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. As a result, they could potentially compete with us for acquisition opportunities and for new business or extensions of the existing services provided by us.

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

Even if our unitholders are dissatisfied, they 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 of directors of our general partner is chosen entirely by its members and not by our unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have limited 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 our unitholders' ability to influence the manner or direction of management.

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 direct transferees and their indirect transferees approved by our general partner (which approval may be granted in its sole discretion) and persons who acquired such units with the prior approval of our general partner, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third party without the consent of our unitholders.

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 our unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of the NGL Energy GP Investor Group to transfer all or a portion of their ownership interest 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.

The IDRs of our general partner may be transferred to a third party.

Prior to the first day of the first quarter beginning after the 10th anniversary of the closing date of our initial public offering ("IPO"), a transfer of IDRs by our general partner requires (except in certain limited circumstances) the consent of a majority of our outstanding common units (excluding common units held by our general partner and its affiliates). However, after the expiration of this period, our general partner may transfer its IDRs to a third party at any time without the consent of our unitholders. If our general partner transfers its IDRs to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its IDRs.

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

If at any time our general partner and its affiliates own more than 80% of the 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, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or may receive a negative return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

Cost reimbursements to our general partner may be substantial and could reduce our cash available to make quarterly distributions to our unitholders.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf, which will be determined by our general partner in its sole discretion in accordance with the terms of our partnership agreement. In determining the costs and expenses allocable to us, our general partner is subject to its fiduciary duty, as modified by our partnership agreement, to the limited partners, which requires it to act in good faith. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. We are managed and operated by executive officers and directors of our general partner. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates, will reduce the amount of cash available for distribution to our unitholders.

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

We expect that we will distribute all of our available cash to our unitholders and will rely primarily on external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, as well as reserves we have established to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or the agreements governing our indebtedness on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

We may issue additional units without the approval of our unitholders, which would dilute the interests of existing unitholders.

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. Our issuance 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 available cash for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner, without the approval of our unitholders, may elect to cause us to issue common units while also maintaining its general partner interest in connection with a resetting of the target distribution levels related to its IDRs. This could result in lower distributions to our unitholders.

Our general partner has the right to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units. The number of common units to be issued to our general partner will be equal to that number of common units that would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the IDRs in the prior two quarters. We anticipate that our general partner would exercise this reset right to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its IDRs and may, therefore, desire to be issued common units rather than retain the right to receive distributions on its IDRs based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units and general partner interests to our general partner in connection with resetting the target distribution levels.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our Partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. 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
- a unitholder's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Our 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 LP Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of 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 interests nor liabilities that are nonrecourse to the partnership are counted for purposes of determining whether a distribution is permitted. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware LP Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability.

The Preferred Units give the holders thereof liquidation and distribution preferences over our common unitholders.

In June 2017 we issued 8,400,000 Class B Preferred Units and in April 2019 we issued 1,800,000 Class C Preferred Units, which rank senior to the common units with respect to distribution rights and rights upon liquidation. Subject to certain exceptions, as long as any Preferred Units remain outstanding, we may not declare any distribution on our common units unless all accumulated and unpaid distributions have been declared and paid on the Preferred Units. In the event of our liquidation, winding-up or dissolution, the holders of the Preferred Units would have the right to receive proceeds from any such transaction before the holders of the common units. The payment of the liquidation preference could result in common unitholders not receiving any consideration if we were to liquidate, dissolve or wind up, either voluntarily or involuntarily. Additionally, the existence of the liquidation preference may reduce the value of the common units, make it harder for us to sell common units in offerings in the future, or prevent or delay a change of control.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. We could lose our status as a partnership for a number of reasons, including not having enough "qualifying income." If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes, our cash available for distribution to our unitholders would be substantially reduced.

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

Despite the fact that we are a limited partnership under Delaware law, a publicly traded partnership such as us will be treated as a corporation for federal income tax purposes unless, for each taxable year, 90% or more of its gross income is "qualifying income" under Section 7704 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). "Qualifying income" includes income and gains derived from the exploration, development, production, processing, transportation, storage and marketing of natural gas, natural gas products, and crude oil or other passive types of income such as certain interest and dividends and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. Although we do not believe based upon our current operations that we are treated as a corporation, we could be treated as a corporation for federal income tax purposes or otherwise subject to taxation as an entity if our gross income is not properly classified as qualifying income, there is a change in our business or there is a change in current law.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently 21% (changed from 35% under the recently enacted tax reform law), and would likely pay state and local income tax at varying rates. Distributions to our unitholders 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 our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the market 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 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.

Our unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our business during our taxable year. However, under the Tax Cuts and Jobs Act of 2017 (the “Act”) signed into law by the President of the United States on December 22, 2017, beginning in tax year 2018, the deductibility of net interest expense is limited to 30% of our adjusted taxable income. For tax years beginning after December 31, 2017 and before January 1, 2022, the Act calculates adjusted taxable income using an EBITDA-based calculation. For tax years beginning January 1, 2022 and thereafter, the calculation of adjusted taxable income will not add back depreciation or amortization. Any disallowed business interest expense is then generally carried forward as a deduction in a succeeding taxable year at the partner level. These limitations might cause interest expense to be deducted by our unitholders in a later period than recognized in the GAAP financial statements.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. 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. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, 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 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. For example, from time to time, members of Congress propose and consider substantive changes to the existing United States federal income tax laws that affect the tax treatment of publicly traded partnerships, including as a result of any fundamental tax reform.

We are unable to predict whether any such change or other proposals will ultimately be enacted or will affect our tax treatment. Any modification to the income tax laws and interpretations thereof may or may not be applied retroactively and could, among other things, cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Moreover, such modifications and change in interpretations may affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. Although we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted, any such changes could negatively impact the value of an investment in our common units.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

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

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

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

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

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholder’s allocable share of our net taxable income decrease the unitholder’s tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units the unitholder sells will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized on any sale of 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 a unitholder sell units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in common units by tax exempt entities, such as employee benefit plans, individual retirement accounts (“IRAs”), Keogh plans and other retirement plans and non-United States persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-United States persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-United States persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-United States person, you should consult your tax advisor before investing in our common units.

We treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the market 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. Any position we take that is inconsistent with applicable Treasury Regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the market value of our common units or result in audit adjustments to tax returns of unitholders.

We have subsidiaries that are treated as corporations for federal income tax purposes and subject to corporate level income taxes.

We conduct a portion of our operations through subsidiaries that are corporations for federal income tax purposes. We may elect to conduct additional operations in corporate form in the future. Our corporate subsidiaries will be subject to corporate level tax, which will reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that our corporate subsidiaries have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based on the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize all aspects 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 our unitholders.

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

Because a unitholder whose units are loaned to a "short seller" to effect a short sale of units may be considered as having disposed of those common units, the unitholder would no longer be treated for federal income 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 a gain or loss from the disposition. Moreover, during the period of the loan to the short seller, 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 loan to a short seller are urged to consult a tax advisor to discuss 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 and monthly conventions for United States federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

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

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

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

There are a number of limitations that may prevent unitholders from using their allocable share of our losses as a deduction against unrelated income. In cases where our unitholders are subject to the passive loss rules (generally, individuals and closely held corporations), 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 its 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. Other limitations that may further restrict the deductibility of our losses by a unitholder include the at-risk rules and the prohibition against loss allocations in excess of the unitholder's tax basis in its units.

Purchasers of our common units may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, holders of our common units are subject to other taxes, including foreign, state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own or control property now or in the future. Holders of our common units are required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions and may be subject to penalties for failure to comply with those requirements. We own assets and conduct business in a number of states, most of which impose a personal income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own or control assets or conduct business in additional states that impose a personal income tax.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We believe that we have satisfactory title or valid rights to use all of our material properties. Although some of these properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-compete agreements entered into in connection with acquisitions and other encumbrances, easements and restrictions, we do not believe that any of these burdens will materially interfere with our continued use of these properties in our business, taken as a whole. Our obligation under the revolving credit facility is secured by liens and mortgages on substantially all of our real and personal property.

Other than as described below, we believe that we have all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local governmental and regulatory authorities that relate to ownership of our properties or the operations of our business.

One of our facilities is operating with all but one of the required permits, as the state of Wyoming has not yet developed a process for issuing permits of this type. We believe that the permit will ultimately be granted, but we are unable to determine the timing of any action by the state of Wyoming.

Our corporate headquarters are in Tulsa, Oklahoma and are leased. We also lease corporate offices in Denver, Colorado and Houston, Texas.

For additional information regarding our properties and the reportable segments in which they are used, see Part I, Item 1–"Business."

Item 3. Legal Proceedings

We are involved from time to time in various legal proceedings and claims arising in the ordinary course of business. For information related to legal proceedings, see the discussion under the captions "Legal Contingencies" and "Environmental Matters" in Note 9 to our consolidated financial statements included in this Annual Report, which is incorporated by reference into this Item 3.

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 are listed on the New York Stock Exchange ("NYSE") under the symbol "NGL." At May 28, 2019, there were approximately 130 common unitholders of record which does not include unitholders for whom common units may be held in "street name."

Cash Distribution Policy

Available Cash

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders as of the record date. Available cash for any quarter generally consists of all cash on hand at the end of that quarter, less the amount of cash reserves established by our general partner, to (i) provide for the proper conduct of our business, (ii) comply with applicable law, any of our debt instruments or other agreements, and (iii) provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.

General Partner Interest

Our general partner is entitled to 0.1% of all quarterly distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 0.1% general partner interest. Our general partner's interest in our distributions may be reduced if we issue additional limited partner units in the future (other than the issuance of common units upon a reset of the IDRs) and our general partner does not contribute a proportionate amount of capital to us to maintain its 0.1% general partner interest.

Incentive Distribution Rights

The general partner will also receive, in addition to distributions on its 0.1% general partner interest, additional distributions based on the level of distributions to the limited partners. These distributions are referred to as "incentive distributions" or "IDRs." Our general partner currently holds the IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

The following table illustrates the percentage allocations of available cash from operating surplus between our limited partner unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest In Distributions" are the percentage interests of our general partner and our limited partner unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for our limited partner unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 0.1% general partner interest, and assume that our general partner has contributed any additional capital necessary to maintain its 0.1% general partner interest and has not transferred its IDRs.

							Marginal Percentage Interest In Distributions	
	Total Quarterly Distribution Per Unit						Limited Partner Unitholders	General Partner (1)
Minimum quarterly distribution					$	0.337500	99.9%	0.1%
First target distribution	above	$	0.337500	up to	$	0.388125	99.9%	0.1%
Second target distribution	above	$	0.388125	up to	$	0.421875	86.9%	13.1%
Third target distribution	above	$	0.421875	up to	$	0.506250	76.9%	23.1%
Thereafter	above	$	0.506250				51.9%	48.1%

(1) The maximum distribution of 48.1% does not include distributions that our general partner may receive on common units that it owns.

Restrictions on the Payment of Distributions

As described in Note 8 to our consolidated financial statements included in this Annual Report, the Credit Agreement contains covenants limiting our ability to pay distributions if we are in default under the Credit Agreement and to pay distributions that are in excess of available cash (as defined in the Credit Agreement). In addition, quarterly distributions on the preferred units must be fully paid for all preceding fiscal quarters before we are permitted to declare or pay any distributions on our common units.

Sales of Unregistered Securities

On April 9, 2019, we issued $450.0 million of 7.50% Senior Unsecured Notes Due 2026 (the “2026 Notes”) in a private placement. The 2026 Notes bear interest, which is payable on April 15 and October 15 of each year, beginning on October 15, 2019. The 2026 Notes mature on April 15, 2026. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

Common Unit Repurchase Program

The following table sets forth certain information with respect to repurchases of common units during the three months ended March 31, 2019:

Period	Total Number of Common Units Purchased	Average Price Paid Per Common Unit		Total Number of Common Units Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Common Units that May Yet Be Purchased Under the Program	
January 1-31, 2019	—	$	—	—	$	—
February 1-28, 2019	11,443	$	11.82	—	$	—
March 1-31, 2019	—	$	—	—	$	—
	11,443			—	$	—

The common units were surrendered by employees to pay tax withholdings in connection with the vesting of restricted common units. As a result, we are deeming the surrenders to be “repurchases.” These repurchases were not part of a publicly announced program to repurchase our common units, nor do we currently have a publicly announced program to repurchase our common units.

Securities Authorized for Issuance Under Equity Compensation Plans

In connection with the completion of our IPO, our general partner adopted the NGL Energy Partners LP Long-Term Incentive Plan. See Part III, Item 12–“Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters –Securities Authorized for Issuance Under Equity Compensation Plan,” which is incorporated by reference into this Item 5.

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Item 6. Selected Financial Data

The following table summarizes selected consolidated historical financial data for the periods and as of the dates indicated. The following table should be read in conjunction with Part I, Item 7–"Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes included in this Annual Report.

The selected consolidated historical financial data at March 31, 2019 and 2018, and for each of the three years in the period ended March 31, 2019 is derived from our audited historical consolidated financial statements included in this Annual Report. The selected consolidated historical financial data at March 31, 2017, 2016 and 2015 and for each of the two years in the period ended March 31, 2016 is derived from our audited historical consolidated financial statements not included in this Annual Report.

	Year Ended March 31,				
	2019	2018	2017	2016	2015
	(in thousands, except per unit data)				
Income Statement Data					
Total revenues	$ 24,016,907	$ 16,907,296	$ 12,707,203	$ 11,468,646	$ 16,312,860
Total cost of sales	$ 23,284,917	$ 16,412,641	$ 12,228,404	$ 10,761,793	$ 15,679,669
Operating income (loss)	$ 141,989	$ (17,174)	$ 205,925	$ (148,699)	$ 43,345
Interest expense	$ 164,726	$ 199,148	$ 149,994	$ 132,749	$ 109,873
Loss (gain) on early extinguishment of liabilities, net	$ 12,340	$ 23,201	$ (24,727)	$ (28,532)	$ —
(Loss) income from continuing operations	$ (63,724)	$ (226,385)	$ 94,802	$ (231,318)	$ (15,229)
Net (loss) income from continuing operations allocated to common unitholders	$ (155,437)	$ (286,521)	$ 57,645	$ (290,725)	$ (69,836)
Basic (loss) income from continuing operations per common unit	$ (1.26)	$ (2.37)	$ 0.53	$ (2.77)	$ (0.81)
Diluted (loss) income from continuing operations per common unit	$ (1.26)	$ (2.37)	$ 0.52	$ (2.77)	$ (0.81)
Cash Flows Data					
Net cash provided by (used in) operating activities	$ 337,250	$ 137,967	$ (25,038)	$ 354,264	$ 262,831
Net cash provided by (used in) investing activities	$ 453,473	$ 270,582	$ (363,126)	$ (445,327)	$ (1,366,221)
Net cash (used in) provided by financing activities	$ (794,245)	$ (394,281)	$ 371,454	$ 80,705	$ 1,134,693
Cash distributions paid per common unit	$ 1.56	$ 1.56	$ 1.56	$ 2.54	$ 2.37
Balance Sheet Data - Period End					
Total assets	$ 5,902,493	$ 6,151,122	$ 6,320,379	$ 5,560,155	$ 6,655,792
Total long-term obligations, net of debt issuance costs and current maturities	$ 2,223,708	$ 2,853,254	$ 3,143,030	$ 3,155,062	$ 2,838,052
Total equity	$ 2,277,818	$ 2,086,095	$ 2,166,802	$ 1,694,065	$ 2,693,432

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

Overview

We are a Delaware limited partnership ("we," "us," "our," or the "Partnership") formed in September 2010. NGL Energy Holdings LLC serves as our general partner. At March 31, 2019, our operations included:

- Crude Oil Logistics
- Water Solutions
- Liquids
- Refined Products and Renewables

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG ("DCC") for net proceeds of $212.4 million in cash, and recorded a gain on disposal of $89.3 million during the year ended March 31, 2018. The Retail Propane businesses subject to this transaction consisted of our operations across the Mid-Continent and Western portions of the United States. On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior Plus Corp. ("Superior") for total consideration of $889.8 million in cash, and recorded a gain on disposal of $408.9 million during the year ended March 31, 2019. We retained our 50% ownership interest in Victory Propane, LLC ("Victory Propane"), which we subsequently sold on August 14, 2018 (see Note 2 to our consolidated financial statements included in this Annual Report on Form 10-K ("Annual Report")). These transactions represent a strategic shift in our operations and will have a significant effect on our operations and financial results going forward. Accordingly, the results of operations and cash flows related to our former Retail Propane segment (including equity in earnings of Victory Propane) have been classified as discontinued operations for all periods presented and prior periods have been retrospectively adjusted in the consolidated statements of operations and consolidated statements of cash flows. In addition, the assets and liabilities related to our former Retail Propane segment have been classified as held for sale within our March 31, 2018 consolidated balance sheet. See Note 1 and Note 17 to our consolidated financial statements included in this Annual Report for a further discussion of the transaction.

Crude Oil Logistics

Our Crude Oil Logistics segment purchases crude oil from producers and marketers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets.

Most of our contracts to purchase or sell crude oil are at floating prices that are indexed to published rates in active markets such as Cushing, Oklahoma. We attempt to reduce our exposure to price fluctuations by using back-to-back physical contracts whenever possible. When back-to-back physical contracts are not optimal, we enter into financially settled derivative contracts as economic hedges of our physical inventory, physical sales and physical purchase contracts. We use our transportation assets to move crude oil from the wellhead to the highest value market. Spreads between crude oil prices in different markets can fluctuate, which may expand or limit our opportunity to generate margins by transporting crude oil to different markets.

The following table summarizes the range of low and high crude oil spot prices per barrel of NYMEX West Texas Intermediate Crude Oil at Cushing, Oklahoma for the periods indicated and the prices at period end:

	Crude Oil Spot Price Per Barrel		
Year Ended March 31,	**Low**	**High**	**At Period End**
2019	$ 42.53	$ 76.41	$ 60.14
2018	$ 42.53	$ 66.14	$ 64.94
2017	$ 35.70	$ 54.45	$ 50.60

We believe volatility in commodity prices will continue, and our ability to adjust to and manage this volatility may impact our financial results.

Our Crude Oil Logistics segment generated an operating loss of $7.4 million during the year ended March 31, 2019, which included a loss of $105.0 million on our transaction with a third party in which they agreed to be fully responsible for our future minimum volume commitment in exchange for $67.7 million of deficiency credits on a contract with a crude oil pipeline operator and $35.3 million in cash (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion). Our Crude Oil Logistics segment generated operating income of $122.9 million during the year ended March 31, 2018, which included a gain of $108.6 million on the sale of our previously held 50% interest in Glass Mountain Pipeline, LLC ("Glass Mountain").

Water Solutions

Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services and sells freshwater to producers for exploration and production activities.

Our water processing facilities are strategically located near areas of high crude oil and natural gas production . A significant factor affecting the profitability of our Water Solutions segment is the extent of exploration and production in the areas near our facilities, which is generally based upon producers' expectations about the profitability of drilling and producing new wells. The primary customer of our Wyoming facility has committed to deliver a specified minimum volume of water to our facility under a long-term contract. The primary customers of our Colorado facilities have committed to deliver all wastewater produced at wells within the DJ Basin to our facilities. Most customers of our other facilities are not under volume commitments, although many of our facilities have acreage dedications or are connected to producer facilities by pipeline.

Our Water Solutions segment generated operating income of $210.5 million during the year ended March 31, 2019, which included a gain of $141.3 million on the sales of our Bakken water disposal business and our South Pecos water disposal business (see Note 16 to our consolidated financial statements included in this Annual Report for a further discussion of both transactions). Our Water Solutions segment generated an operating loss of $24.2 million during the year ended March 31, 2018.

Liquids

Our Liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada. Our Liquids segment owns 27 terminals throughout the United States and a salt dome storage facility joint venture in Utah, operates a fleet of leased railcars, and leases underground storage capacity. We attempt to reduce our exposure to price fluctuations by using back-to-back physical contracts and pre-sale agreements that allow us to lock in a margin on a percentage of our winter volumes. We also enter into financially settled derivative contracts as economic hedges of our physical inventory, physical sales and physical purchase contracts.

Our wholesale Liquids business is a "cost-plus" business that can be affected by both price fluctuations and volume variations. We establish our selling price based on a pass-through of our product supply, transportation, handling, storage, and capital costs plus an acceptable margin.

Weather conditions and gasoline blending can have a significant impact on the demand for propane and butane, and sales volumes and prices are typically higher during the colder months of the year. Consequently, our revenues, operating profits, and operating cash flows are typically lower in the first and second quarters of our fiscal year.

The following table summarizes the range of low and high propane spot prices per gallon at Conway, Kansas, and Mt. Belvieu, Texas, two of our main pricing hubs, for the periods indicated and the prices at period end:

	Conway, Kansas			Mt. Belvieu, Texas		
	Propane Spot Price Per Gallon			Propane Spot Price Per Gallon		
Year Ended March 31,	**Low**	**High**	**At Period End**	**Low**	**High**	**At Period End**
2019	$ 0.50	$ 0.88	$ 0.55	$ 0.58	$ 1.11	$ 0.64
2018	$ 0.53	$ 0.98	$ 0.66	$ 0.57	$ 1.02	$ 0.80
2017	$ 0.35	$ 0.89	$ 0.56	$ 0.42	$ 0.93	$ 0.61

The following table summarizes the range of low and high butane spot prices per gallon at Mt. Belvieu, Texas for the periods indicated and the prices at period end:

	Butane Spot Price Per Gallon		
Year Ended March 31,	**Low**	**High**	**At Period End**
2019	$ 0.71	$ 1.51	$ 0.75
2018	$ 0.64	$ 1.12	$ 0.78
2017	$ 0.52	$ 1.42	$ 0.75

We believe volatility in commodity prices will continue, and our ability to adjust to and manage this volatility may impact our financial results.

Our Liquids segment generated an operating loss of $2.9 million during the year ended March 31, 2019, which included a goodwill impairment charge of $66.2 million related to our salt dome storage facility joint venture in Utah (see Note 6 to our consolidated financial statements included in this Annual Report). Our Liquids segment generated an operating loss of $93.1 million during the year ended March 31, 2018, which included a goodwill impairment charge of $116.9 million related to our salt dome storage facility joint venture in Utah (see Note 6 to our consolidated financial statements included in this Annual Report).

Refined Products and Renewables

Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations , purchases refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedules them for delivery at various locations throughout the country. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties. We sell our products to commercial and industrial end users, independent retailers, distributors, marketers, government entities, and other wholesalers of refined petroleum products. We sell our products at terminals owned by third parties.

The following table summarizes the range of low and high Gulf Coast gasoline spot prices per barrel using NYMEX gasoline prompt-month futures for the periods indicated and the prices at period end:

	Gasoline Spot Price Per Barrel		
Year Ended March 31,	**Low**	**High**	**At Period End**
2019	$ 52.45	$ 95.35	$ 79.62
2018	$ 59.24	$ 89.88	$ 84.75
2017	$ 53.44	$ 71.40	$ 71.40

The following table summarizes the range of low and high diesel spot prices per barrel using NYMEX ULSD prompt-month futures for the periods indicated and the prices at period end:

	Diesel Spot Price Per Barrel		
Year Ended March 31,	**Low**	**High**	**At Period End**
2019	$ 69.81	$ 102.36	$ 82.88
2018	$ 57.32	$ 89.71	$ 85.19
2017	$ 45.13	$ 71.58	$ 66.09

Our Refined Products and Renewables segment generated operating income of $27.5 million and $56.7 million during the years ended March 31, 2019 and 2018, respectively.

Consolidated Results of Operations

The following table summarizes our consolidated statements of operations for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Total revenues	$ 24,016,907	$ 16,907,296	$ 12,707,203
Total cost of sales	23,284,917	16,412,641	12,228,404
Operating expenses	240,684	201,068	189,003
General and administrative expense	107,534	98,129	105,805
Depreciation and amortization	212,860	209,020	180,239
Loss (gain) on disposal or impairment of assets, net	34,296	(17,104)	(208,890)
Revaluation of liabilities	(5,373)	20,716	6,717
Operating income (loss)	141,989	(17,174)	205,925
Equity in earnings of unconsolidated entities	2,533	7,539	3,830
Revaluation of investments	—	—	(14,365)
Interest expense	(164,726)	(199,148)	(149,994)
(Loss) gain on early extinguishment of liabilities, net	(12,340)	(23,201)	24,727
Other (expense) income, net	(29,946)	6,953	26,612
(Loss) income from continuing operations before income taxes	(62,490)	(225,031)	96,735
Income tax expense	(1,234)	(1,354)	(1,933)
(Loss) income from continuing operations	(63,724)	(226,385)	94,802
Income from discontinued operations, net of tax	403,119	156,780	49,072
Net income (loss)	339,395	(69,605)	143,874
Less: Net loss (income) attributable to noncontrolling interests	20,206	(240)	(6,832)
Less: Net loss (income) attributable to redeemable noncontrolling interests	446	(1,030)	—
Net income (loss) attributable to NGL Energy Partners LP	$ 360,047	$ (70,875)	$ 137,042

Items Impacting the Comparability of Our Financial Results

Our current and future results of operations may not be comparable to our historical results of operations for the periods presented due to business combinations, disposals and other transactions.

Recent Developments

Transactions during the Three Months Ended March 31, 2019

Repurchase and Redemption of Senior Unsecured Notes

During the three months ended March 31, 2019, we repurchased $11.9 million of the 2019 Notes (as defined herein). See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

On March 15, 2019, we paid $329.7 million to redeem all of our outstanding 2019 Notes. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

Credit Agreement

On February 6, 2019, we amended the Credit Agreement (as defined herein) to, among other things, reset and increase the basket for the repurchase of common units, decrease the maximum total leverage indebtedness ratio for future quarters and amend the defined term “Consolidated EBITDA.” See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

Subsequent Events

See Note 19 to our consolidated financial statements included in this Annual Report for a discussion of transactions that occurred subsequent to March 31, 2019.

Acquisitions

As discussed below, we completed numerous acquisitions during the years ended March 31, 2019 and 2018. These acquisitions impact the comparability of our results of operations between our current and prior fiscal years.

During the year ended March 31, 2019, in our Water Solutions segment, we acquired the remaining 18.375% interest in NGL Water Pipelines, LLC, six saltwater disposal facilities (including 22 saltwater disposal wells), two ranches and four freshwater facilities (including 45 freshwater wells). In our Liquids segment, we acquired the natural gas liquids terminal business of DCP Midstream, LP and in our Refined and Renewables segment, we acquired two refined products terminals. See Note 4 to our consolidated financial statements included in this Annual Report for a further discussion.

In our Retail Propane segment, we acquired three retail propane businesses and the remaining 40% interest in Atlantic Propane, LLC. The assets and liabilities of these retail propane transactions were included in the sale of virtually all of our remaining Retail Propane segment on July 10, 2018 and the operations have been classified as discontinued. See Note 4 and Note 17 to our consolidated financial statements included in this Annual Report for a further discussion.

During the year ended March 31, 2018, in our Water Solutions segment, we acquired the remaining 50% ownership interest in NGL Solids Solutions, LLC, and in our Retail Propane segment, we acquired seven retail propane businesses and certain assets from Victory Propane. The assets and liabilities of these retail propane businesses are included in current assets and current liabilities held for sale in our March 31, 2018 consolidated balance sheet and the operations have been classified as discontinued. See Note 13 and Note 17 to our consolidated financial statements included in this Annual Report for a further discussion.

Subsequent Events

See Note 19 to our consolidated financial statements included in this Annual Report for a discussion of the acquisitions that occurred subsequent to March 31, 2019.

Dispositions

Sale of South Pecos Water Disposal Business

On February 28, 2019, we completed the sale of our South Pecos water disposal business to a subsidiary of WaterBridge Resources LLC for $232.2 million in net cash proceeds and recorded a gain on disposal of $107.9 million during the year ended March 31, 2019. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Water Solutions segment have not been classified as discontinued operations.

Sale of Bakken Saltwater Disposal Business

On November 30, 2018, we completed the sale of NGL Water Solutions Bakken, LLC to an affiliate of Tallgrass Energy, LP for $85.0 million in net cash proceeds and recorded a gain on disposal of $33.4 million during the year ended March 31, 2019. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Water Solutions segment have not been classified as discontinued operations.

Sale of Retail Propane Business

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC. On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior and on August 14, 2018, we sold our previously held interest in Victory Propane. See “Overview” above for a further discussion.

Sawtooth Joint Venture

On March 30, 2018, we completed the transaction to form a joint venture with Magnum Liquids, LLC, a portfolio company of Haddington Ventures LLC, along with Magnum Development, LLC and other Haddington-sponsored investment entities (collectively "Magnum") to focus on the storage of natural gas liquids and refined products by combining our Sawtooth salt dome storage facility with Magnum's refined products rights and adjacent leasehold. Magnum acquired an approximately 28.5% interest in Sawtooth from us, in exchange for consideration consisting of a cash payment of approximately $37.6 million (excluding working capital) and the contribution of certain refined products rights and adjacent leasehold. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Interest in Glass Mountain

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain for net proceeds of $292.1 million and recorded a gain on disposal of $108.6 million during the three months ended December 31, 2017 . See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Crude Oil Logistics segment have not been classified as discontinued operations.

Trends

Crude oil prices can fluctuate widely based on changes in supply and demand conditions. The opportunity to generate revenues in our Crude Oil Logistics business is heavily influenced by the volume of crude oil being produced. Crude oil prices declined sharply during the period from July 2014 through February 2016. Crude oil prices have rebounded and at March 31, 2019, the spot price for NYMEX West Texas Intermediate Crude Oil at Cushing, Oklahoma was $60.14 per barrel. While crude oil production in the United States has been strong in recent years, a sharp decline in crude oil prices could reduce the incentive for producers to expand production. Low crude oil prices could result in declines in crude oil production and may adversely impact volumes and margins in our Crude Oil Logistics business. Crude oil price declines have had an adverse impact on many participants in the energy markets, and the inherent risk of customer or counterparty nonperformance is higher when crude oil prices are low or in decline.

From January 2015 to January 2018, crude oil markets were in contango, a condition in which forward crude oil prices are greater than spot prices. Our Crude Oil Logistics business benefits when the market is in contango, as increasing prices result in inventory holding gains during the time between when we purchase inventory and when we sell it. In addition, we are able to better utilize our storage assets when contango markets justify storing barrels. During the year ended March 31, 2019, crude oil markets have moved from being in backwardation to fairly flat. Backwardation is a condition in which forward crude oil prices are lower than spot prices. When markets are in backwardation, falling prices typically have an unfavorable impact on our margins.

Our opportunity to generate revenues in our Water Solutions business is based on the level of production of natural gas and crude oil in the areas where our facilities are located. As described above, crude oil prices declined sharply since July 2014 but have increased since March 31, 2016. Also, drilling rigs and production have increased since March 31, 2016, particularly in the Permian and DJ Basins which has positively impacted the volumes of our Water Solutions business (during the three months ended March 31, 2019 we processed 860,000 barrels of wastewater per day, compared to 761,000 barrels of wastewater per day during the three months ended March 31, 2018). A portion of the revenues in our Water Solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater. These recovered hydrocarbon revenues have increased due primarily to an increase in the volume of wastewater processed at existing facilities as well as facilities acquired from acquisitions and an increase in crude oil prices; however, these revenues were negatively impacted by a lower percentage of skim oil volumes recovered per wastewater barrel processed. This lower percentage was due primarily to an increase in wastewater transported through pipelines (which contains less oil per barrel of wastewater), as well as operational changes in the DJ Basin, which have resulted in lower per-barrel revenues for our Water Solutions business.

An important element of our Refined Products and Renewables segment relates to the marketing of refined products in the Southeast and East Coast regions. We purchase product in the Gulf Coast, transport the product on third party pipelines, and sell the product at terminals owned by third parties. Most of the contracts with these customers are one year in duration, with pricing indexed to prices in the Gulf Coast at the date of sale plus a specified differential. To operate this business we maintain inventory in transit on third party pipelines and at destination terminals where we sell the product. The value of this inventory will increase or decrease as market prices change. In order to mitigate this risk, we enter into futures contracts, which are only available based on New York Harbor pricing. Because our contracts are indexed to Gulf Coast prices and our futures contracts are based on New York Harbor prices, the futures contracts are not a perfect hedge against our inventory holding risk. During any given period, spreads between prices in the Gulf Coast and New York Harbor could narrow or widen, which could reduce the effectiveness of the futures contracts as a hedge of the inventory holding risk. The tenor of these futures contracts, which are typically six months to one year in duration at inception, can also contribute to volatility in earnings among individual quarters within a fiscal year.

During the year ended March 31, 2019, prices for refined products increased. Gulf Coast prices, on which our sales contracts are based, increased less than the New York Harbor prices, on which our futures contracts are based, which had an unfavorable impact on our cost of sales. Based on historical experience, we generally expect the spreads between Gulf Coast and New York Harbor prices to be more consistent over the course of a contract year than during any individual quarter within the year, and that we should expect more volatility in cost of sales among quarters within a fiscal year than we would expect during a full fiscal year.

Seasonality

Seasonality impacts our Liquids and Refined Products and Renewables segments. Consequently, for our Liquids business, revenues, operating profits and operating cash flows are generated mostly in the third and fourth quarters of our fiscal year. The seasonal motor fuel blend during the third quarter of our fiscal year impacts the value of our gasoline inventory in our Refined Products and Renewables business and also represents a period when we build inventory into our system. We borrow under the Revolving Credit Facility to supplement our operating cash flows during the periods in which we are building inventory. See “–Liquidity, Sources of Capital and Capital Resource Activities–Cash Flows.”

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Segment Operating Results for the Years Ended March 31, 2019 and 2018

Crude Oil Logistics

The following table summarizes the operating results of our Crude Oil Logistics segment for the periods indicated:

	Year Ended March 31, 2019	Year Ended March 31, 2018	Change
	(in thousands, except per barrel amounts)		
Revenues:			
Crude oil sales	$ 3,011,355	$ 2,151,203	$ 860,152
Crude oil transportation and other	161,336	122,786	38,550
Total revenues (1)	3,172,691	2,273,989	898,702
Expenses:			
Cost of sales-excluding impact of derivatives	2,939,702	2,120,640	819,062
Cost of sales-derivative (gain) loss	(1,085)	7,021	(8,106)
Operating expenses	53,352	47,846	5,506
General and administrative expenses	6,512	6,584	(72)
Depreciation and amortization expense	74,165	80,387	(6,222)
Loss (gain) on disposal or impairment of assets, net	107,424	(111,393)	218,817
Total expenses	3,180,070	2,151,085	1,028,985
Segment operating (loss) income	$ (7,379)	$ 122,904	$ (130,283)
Crude oil sold (barrels)	48,366	39,626	8,740
Crude oil transported on owned pipelines (barrels)	42,564	33,454	9,110
Crude oil storage capacity - owned and leased (barrels) (2)	5,232	6,159	(927)
Crude oil storage capacity leased to third parties (barrels) (2)	2,564	2,641	(77)
Crude oil inventory (barrels) (2)	827	1,219	(392)
Crude oil sold ($/barrel)	$ 62.262	$ 54.288	$ 7.974
Cost per crude oil sold ($/barrel)	$ 60.758	$ 53.694	$ 7.064
Crude oil product margin ($/barrel)	$ 1.504	$ 0.594	$ 0.910

(1) Revenues include $36.1 million and $13.9 million of intersegment sales during the years endedMarch 31, 2019 and 2018, respectively, that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2019 and March 31, 2018, respectively.

Crude Oil Sales Revenues. The increase was due primarily to an increase in crude oil prices and sales volumes during the year ended March 31, 2019, compared to the year ended March 31, 2018. The increase in crude oil prices throughout our fiscal year 2019 has led to an increase in production volumes for us to market. We continue to market crude oil volumes in the majority of the basins across the United States to support our various pipeline, terminal and transportation assets.

Crude Oil Transportation and Other Revenues. The increase was due to our Grand Mesa Pipeline, which increased revenues by $17.0 million during the year ended March 31, 2019, compared to the year ended March 31, 2018, primarily due to increased production growth in the DJ Basin. During the year ended March 31, 2019, approximately 42.6 million barrels of crude oil were transported on the Grand Mesa Pipeline, which averaged approximately 117,000 barrels per day, physically, and financial volumes averaged approximately 120,000 barrels per day (volume amounts are from both internal and external parties). In addition, during the year ended March 31, 2019, a new crude marketing contract increased revenues by $23.4 million. This was partially offset by a reduction in railcar sublease revenue.

Cost of Sales-Excluding Impact of Derivatives. The increase was due primarily to an increase in crude oil prices and sales volumes during the year ended March 31, 2019, compared to the year ended March 31, 2018.

Cost of Sales-Derivatives. Our cost of sales during the year ended March 31, 2019 included $0.6 million of net realized losses on derivatives and $1.7 million of net unrealized gains on derivatives. Our cost of sales during the year ended

March 31, 2018 included $4.2 million of net realized losses on derivatives and $2.8 million of net unrealized losses on derivatives.

Operating and General and Administrative Expenses . The increase was due primarily to utilities related to the higher volumes transported on the Grand Mesa Pipeline.

Depreciation and Amortization Expense. The decrease was due primarily to downsizing our fleet of crude transportation assets, which decreased depreciation and amortization expense by $4.3 million during the year ended March 31, 2019, compared to the year ended March 31, 2018. The decrease was also due to certain intangible assets being fully amortized in prior periods.

Loss (Gain) on Disposal or Impairment of Assets, Net . During the year ended March 31, 2019, we recorded a net loss of $107.4 million, which included a loss of $105.0 million on our transaction with a third party in which they agreed to be fully responsible for our future minimum volume commitment in exchange for $67.7 million of deficiency credits on a contract with a crude oil pipeline operator and $35.3 million in cash (see Note 2 and Note 13 to our consolidated financial statements included in this Annual Report). The loss also includes additional costs related to this transaction of $2.0 million. In addition, we recorded a loss of $1.3 million related to the sale of two terminals during the year ended March 31, 2019. During the year ended March 31, 2018, we recorded a gain of $108.6 million on the sale of our previously held 50% interest in Glass Mountain (see Note 16 to our consolidated financial statements included in this Annual Report). In addition, we recorded a net gain of $2.8 million on the sales of certain other assets.

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Water Solutions

The following table summarizes the operating results of our Water Solutions segment for the periods indicated:

	Year Ended March 31,		
	2019	2018	Change
	(in thousands, except per barrel and per day amounts)		
Revenues:			
Wastewater disposal service fees	$ 189,947	$ 149,114	$ 40,833
Sale of recovered hydrocarbons	72,678	58,948	13,730
Other service revenues	39,061	21,077	17,984
Total revenues	301,686	229,139	72,547
Expenses:			
Cost of sales-excluding impact of derivatives	2,668	2,150	518
Cost of sales-derivative (gain) loss	(13,455)	17,195	(30,650)
Operating expenses	130,748	105,200	25,548
General and administrative expenses	6,615	2,623	3,992
Depreciation and amortization expense	108,162	98,623	9,539
(Gain) loss on disposal or impairment of assets, net	(138,204)	6,863	(145,067)
Revaluation of liabilities	(5,373)	20,716	(26,089)
Total expenses	91,161	253,370	(162,209)
Segment operating income (loss)	$ 210,525	$ (24,231)	$ 234,756
Wastewater processed (barrels per day)			
Permian Basin	461,456	289,360	172,096
Eagle Ford Basin	270,849	235,713	35,136
DJ Basin	161,010	113,771	47,239
Other Basins	53,799	68,466	(14,667)
Total	947,114	707,310	239,804
Solids processed (barrels per day)	6,957	5,662	1,295
Skim oil sold (barrels per day)	3,567	3,210	357
Service fees for wastewater processed ($/barrel)	$ 0.55	$ 0.58	$ (0.03)
Recovered hydrocarbons for wastewater processed ($/barrel)	$ 0.21	$ 0.23	$ (0.02)
Operating expenses for wastewater processed ($/barrel)	$ 0.38	$ 0.41	$ (0.03)

Wastewater Disposal Service Fee Revenues. The increase was due primarily to an increase in the volume of wastewater processed at existing facilities as well as facilities acquired from acquisitions. We continue to benefit from the increased oil and gas production and rig counts as compared to the prior year in the basins in which we operate, particularly in the Permian Basin.

Recovered Hydrocarbon Revenues. The increase was due primarily to an increase in the volume of wastewater processed at existing facilities as well as facilities acquired from acquisitions and an increase in crude oil prices; however, these revenues were negatively impacted by a lower percentage of skim oil volumes recovered per wastewater barrel processed. This lower percentage was due primarily to an increase in wastewater transported through pipelines (which contains less oil per barrel of wastewater), as well as operational changes in the DJ Basin.

Other Service Revenues. Other service revenues primarily include solids disposal revenues, water pipeline revenues and freshwater revenues, all of which increased during the year ended March 31, 2019 due to increased volumes as well as acquisitions.

Cost of Sales-Excluding Impact of Derivatives. The increase was due primarily to an increase in expenses to bring wastewater to certain of our water solutions facilities.

Cost of Sales-Derivatives. We enter into derivatives in our Water Solutions segment to protect against the risk of a decline in the market price of the hydrocarbons we expect to recover when processing the wastewater and selling the skim oil. Our cost of sales during the year ended March 31, 2019 included $15.5 million of net unrealized gains on derivatives and $2.1 million of net realized losses on derivatives. In December 2018, we settled derivative contracts that had scheduled settlement dates from January 2019 through December 2020 and recorded a gain of $8.4 million on those derivatives. Our cost of sales during the year ended March 31, 2018 included $13.7 million of net unrealized losses on derivatives and $3.5 million of net realized losses on derivatives.

Operating and General and Administrative Expenses. The increase was due primarily to the increase in the number of water disposal facilities and wells that we own and operated due to higher volumes processed at existing facilities and facilities acquired from acquisitions, partially offset by cost reduction efforts. Due to the higher volumes processed, our cost per barrel has decreased, as shown in the table above. Also contributing to the increase was an increase in acquisition expenses related to one of our ranch acquisitions.

Depreciation and Amortization Expense. The increase was due primarily to acquisitions and developed facilities, partially offset by the disposition of our Bakken and South Pecos water disposal businesses and certain intangible assets being fully amortized during the years ended March 31, 2019 and 2018.

(Gain) Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2019, we completed the sale of our South Pecos water disposal business and recorded a gain on disposal of $107.9 million and the sale of our Bakken water disposal business and recorded a gain on disposal of $33.4 million (see Note 16 to our consolidated financial statements included in this Annual Report for a further discussion of both transactions). In addition, we recorded a net loss of $3.1 million on the disposals of certain other assets during the year ended March 31, 2019.

During the year ended March 31, 2018, we recorded a loss of $8.2 million on the disposals of certain assets, partially offset by a gain of $1.3 million for the termination of a non-compete agreement, which included the carrying value of the non-compete agreement intangible asset that was written off (see Note 7 to our consolidated financial statements included in this Annual Report).

Revaluation of Liabilities. The revaluation of liabilities represents the change in the valuation of our contingent consideration liabilities related to royalty agreements acquired as part of certain business combinations. The reduction in expense during the year ended March 31, 2019 was due primarily to lower expected production from new customers and an increase in facilities due to acquisitions, resulting in a decrease to the expected future royalty payment. The expense during the year ended March 31, 2018 was due primarily to higher actual and expected production from new customers, resulting in an increase to the expected future royalty payment.

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Liquids

The following table summarizes the operating results of our Liquids segment for the periods indicated:

	Year Ended March 31, 2019	Year Ended March 31, 2018	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$ 1,179,087	$ 1,203,486	$ (24,399)
Cost of sales-excluding impact of derivatives	1,111,678	1,165,414	(53,736)
Cost of sales-derivative loss (gain)	5,856	(5,577)	11,433
Product margin	61,553	43,649	17,904
Butane sales:			
Revenues (1)	637,076	562,066	75,010
Cost of sales-excluding impact of derivatives	609,833	535,017	74,816
Cost of sales-derivative (gain) loss	(1,264)	19,616	(20,880)
Product margin	28,507	7,433	21,074
Other product sales:			
Revenues (1)	599,166	432,570	166,596
Cost of sales-excluding impact of derivatives	570,866	414,980	155,886
Cost of sales-derivative loss (gain)	1,001	(173)	1,174
Product margin	27,299	17,763	9,536
Service revenues:			
Revenues (1)	23,003	22,548	455
Cost of sales	3,030	3,930	(900)
Product margin	19,973	18,618	1,355
Expenses:			
Operating expenses	41,360	32,792	8,568
General and administrative expenses	5,672	5,331	341
Depreciation and amortization expense	25,997	24,937	1,060
Loss on disposal or impairment of assets, net	67,213	117,516	(50,303)
Total expenses	140,242	180,576	(40,334)
Segment operating loss	$ (2,910)	$ (93,113)	$ 90,203
Liquids storage capacity - owned and leased (gallons) (2)	397,343	438,968	(41,625)
Propane sold (gallons)	1,383,986	1,361,173	22,813
Propane sold ($/gallon)	$ 0.852	$ 0.884	$ (0.032)
Cost per propane sold ($/gallon)	$ 0.807	$ 0.852	$ (0.045)
Propane product margin ($/gallon)	$ 0.045	$ 0.032	$ 0.013
Propane inventory (gallons) (2)	44,757	48,928	(4,171)
Propane storage capacity leased to third parties (gallons) (2)	30,440	29,662	778
Butane sold (gallons)	610,968	544,750	66,218
Butane sold ($/gallon)	$ 1.043	$ 1.032	$ 0.011
Cost per butane sold ($/gallon)	$ 0.996	$ 1.018	$ (0.022)
Butane product margin ($/gallon)	$ 0.047	$ 0.014	$ 0.033
Butane inventory (gallons) (2)	21,677	15,385	6,292
Butane storage capacity leased to third parties (gallons) (2)	62,185	51,660	10,525
Other products sold (gallons)	498,751	400,405	98,346
Other products sold ($/gallon)	$ 1.201	$ 1.080	$ 0.121
Cost per other products sold ($/gallon)	$ 1.147	$ 1.036	$ 0.111
Other products product margin ($/gallon)	$ 0.054	$ 0.044	$ 0.010
Other products inventory (gallons) (2)	9,158	5,822	3,336

(1) Revenues include $23.3 million and $4.7 million of intersegment sales during the years ended March 31, 2019 and 2018, respectively, that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2019 and March 31, 2018, respectively.

Propane Sales and Cost of Sales-Excluding Impact of Derivatives. The decreases in revenues and cost of sales-excluding impact of derivatives were due primarily to a decline in product pricing and lower railcar costs.

Cost of Sales-Derivatives. Our cost of wholesale propane sales included $1.4 million of net unrealized losses on derivatives and $4.4 million of net realized losses on derivatives during the year ended March 31, 2019. During the year ended March 31, 2018, our cost of wholesale propane sales included $1.0 million of net unrealized gains on derivatives and $4.6 million of net realized gains on derivatives.

Propane product margins per gallon of propane sold were higher during the year ended March 31, 2019 than during the year ended March 31, 2018 due to favorable market conditions.

Butane Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due primarily to higher commodity prices in the first six months of the year, partially offset by declining commodity prices in the latter half of the year. Volumes increased due to favorable market conditions.

Cost of Sales-Derivatives. Our cost of butane sales during the year ended March 31, 2019 included $1.5 million of net unrealized gains on derivatives and $0.3 million of net realized losses on derivatives. Our cost of butane sales included $0.5 million of net unrealized losses on derivatives and $19.1 million of net realized losses on derivatives during the year ended March 31, 2018.

Butane product margins per gallon of butane sold were higher during the year ended March 31, 2019 than during the year ended March 31, 2018 due primarily to a strong pricing market and generally strong demand.

Other Products Sales and Cost of Sales-Excluding Impact of Derivatives. Other product volumes increase was facilitated by a price arbitrage allowing for products to be sold across markets.

Cost of Sales-Derivatives. Our cost of sales of other products included less than $0.1 million of net unrealized gains on derivatives and $1.0 million of net realized losses on derivatives during the year ended March 31, 2019. Our cost of sales of other products during the year ended March 31, 2018 included $0.1 million of net unrealized gains on derivatives and $0.1 million of net realized gains on derivatives.

Other product sales product margins during the year ended March 31, 2019 were higher primarily due to a strong pricing environment and higher than anticipated production.

Service Revenues. This revenue includes storage, terminaling and transportation services income. The increase during the year ended March 31, 2019 was primarily related to an increase in revenues at our Port Hudson terminal as well as high railcar fleet utilization.

Operating and General and Administrative Expenses. Expenses were higher due to an increase in employee commissions resulting from increased profit margins, increased expenses related to the Sawtooth joint venture, increased expenses in March related to our natural gas liquids terminal acquisition and a credit in the prior year for ad valorem taxes.

Depreciation and Amortization Expense. Expense for the current year was consistent with the prior year.

Loss on Disposal or Impairment of Assets, Net. During the years ended March 31, 2019 and 2018, we recorded goodwill impairment charges of $66.2 million and $116.9 million, respectively, within our natural gas liquids salt cavern storage reporting unit due to the decreased demand for natural gas liquid storage and resulting decline in revenues and earnings as compared to actual and projected results of prior and future periods (see Note 6 to our consolidated financial statements included in this Annual Report). During the years ended March 31, 2019 and 2018, we recorded a net loss of $1.0 million and $0.6 million, respectively, related to the retirement of assets.

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Refined Products and Renewables

The following table summarizes the operating results of our Refined Products and Renewables segment for the periods indicated.

	Year Ended March 31, 2019	Year Ended March 31, 2018	Change
	(in thousands, except per barrel amounts)		
Refined products sales:			
Revenues-excluding impact of derivatives (1)	$ 17,951,780	$ 11,827,222	$ 6,124,558
Cost of sales-excluding impact of derivatives	17,937,504	11,709,786	6,227,718
Derivative (gain) loss	(22,023)	77,055	(99,078)
Product margin	36,299	40,381	(4,082)
Renewables sales:			
Revenues-excluding impact of derivatives	270,302	373,669	(103,367)
Cost of sales-excluding impact of derivatives	276,094	362,457	(86,363)
Derivative (gain) loss	(2,661)	1,467	(4,128)
Product (loss) margin	(3,131)	9,745	(12,876)
Service fees and other revenues	15,605	300	15,305
Expenses:			
Operating expenses	13,714	14,057	(343)
General and administrative expenses	9,108	8,433	675
Depreciation and amortization expense	1,518	1,294	224
Gain on disposal or impairment of assets, net	(3,026)	(30,098)	27,072
Total expense (income), net	21,314	(6,314)	27,628
Segment operating income	$ 27,459	$ 56,740	$ (29,281)
Gasoline sold (barrels)	173,475	108,427	65,048
Diesel sold (barrels)	53,662	56,020	(2,358)
Ethanol sold (barrels)	2,553	3,438	(885)
Biodiesel sold (barrels)	991	2,079	(1,088)
Refined products and renewables storage capacity - leased (barrels) (2)	9,745	9,911	(166)
Refined products and renewables storage capacity sub-leased to third parties (barrels) (2)	235	1,068	(833)
Gasoline inventory (barrels) (2)	2,807	3,367	(560)
Diesel inventory (barrels) (2)	1,258	1,419	(161)
Ethanol inventory (barrels) (2)	1,640	701	939
Biodiesel inventory (barrels) (2)	310	261	49
Refined products sold ($/barrel)	$ 79.035	$ 71.921	$ 7.114
Cost per refined products sold ($/barrel)	$ 78.875	$ 71.676	$ 7.199
Refined products product margin ($/barrel)	$ 0.160	$ 0.245	$ (0.085)
Renewable products sold ($/barrel)	$ 76.270	$ 67.730	$ 8.540
Cost per renewable products sold ($/barrel)	$ 77.154	$ 65.964	$ 11.190
Renewable products product (loss) margin ($/barrel)	$ (0.884)	$ 1.766	$ (2.650)

(1) Revenues include $0.3 million of intersegment sales during the year endedMarch 31, 2018 that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2019 and March 31, 2018, respectively.

Refined Products Revenues-Excluding Impact of Derivatives and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues-excluding impact of derivatives and cost of sales-excluding impact of derivatives were due to an increase in refined products prices and increased volumes. The increase in prices was due primarily to supply and demand for refined fuels at our wholesale locations. The increased volumes were due primarily to an expansion of our refined products operations and the continued demand for motor fuels. During the year ended March 31, 2019, Gulf Coast prices increased less than during the year ended March 31, 2018, which negatively affected our margins-excluding impact of derivatives.

Refined Products-Derivative (Gain) Loss. Our margin during the year ended March 31, 2019 included a gain of $22.0 million from our risk management activities due primarily to NYMEX futures prices decreasing on our short future positions. Our margin during the year ended March 31, 2018 included a loss of $77.1 million from our risk management activities due primarily to NYMEX futures prices increasing on our short future positions.

Renewables Revenues-Excluding Impact of Derivatives and Cost of Sales-Excluding Impact of Derivatives. The decreases in revenues-excluding impact of derivatives and cost of sales-excluding impact of derivatives were due primarily to decreased volumes from the loss of a marketing contract with E Energy Adams, LLC in December 2017, partially offset by an increase in renewables prices due primarily to supply and demand for renewable fuels. In addition, the favorable margin for the year ended March 31, 2018 included the impact of the biodiesel tax credit being reinstated in February 2018 related to calendar year 2017. Currently, the biodiesel tax credit has not been reinstated for calendar year 2018.

Renewables-Derivative (Gain) Loss. Our margin during the year ended March 31, 2019 included a gain of $2.7 million from our risk management activities due primarily to unrealized gains on our open forward positions. Our margin during the year ended March 31, 2018 included a loss of $1.5 million from our risk management activities due primarily to NYMEX futures prices increasing on our short future positions, partially offset by unrealized gains on our open forward positions.

Service Fees and Other Revenues. The increase was due primarily to an early termination settlement for one our sublease agreements during the three months ended June 30, 2018 and the reclassification of sublease revenue to Service Fees and Other Revenues beginning April 1, 2018 in conjunction with the adoption of ASC 606. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion.

Operating and General and Administrative Expenses. The increase was due primarily to expansion of our refined products operations into gas blending, partially offset by lower environmental expense during the year ended March 31, 2019 from an insurance recovery received during the three months ended June 30, 2018 related to a historical environmental indemnification agreement.

Depreciation and Amortization Expense. The increase was due primarily to acquisitions during the year ended March 31, 2019.

Gain on Disposal or Impairment of Assets, Net . During the year ended March 31, 2019, we recorded a gain of $3.0 million on the sale of our previously held 20% interest in E Energy Adams, LLC (see Note 2 to our consolidated financial statements included in this Annual Report). During the year ended March 31, 2018, we recognized $30.1 million of the deferred gain from the sale of the general partner interest in TLP in February 2016. There is not a similar amount of deferred gain recognized during the year ended March 31, 2019 due to our adoption of ASC 606. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion of the reasons for the realization of the deferred gain.

Corporate and Other

The operating loss within “Corporate and Other” includes the following components for the periods indicated:

	Year Ended March 31, 2019	Year Ended March 31, 2018	Change
	(in thousands)		
Other revenues:			
Revenues	$ 1,362	$ 1,174	$ 188
Cost of sales	1,929	530	1,399
(Loss) margin	(567)	644	(1,211)
Expenses:			
Operating expenses	1,605	1,173	432
General and administrative expenses	79,627	75,158	4,469
Depreciation and amortization expense	3,018	3,779	(761)
Loss on disposal or impairment of assets, net	889	8	881
Total expenses	85,139	80,118	5,021
Operating loss	$ (85,706)	$ (79,474)	$ (6,232)

General and Administrative Expenses. The increase during the year ended March 31, 2019 was due primarily to higher equity-based compensation expense. During the year ended March 31, 2019, equity-based compensation expense was $37.6 million, compared to $35.2 million during the year ended March 31, 2018. The increase is primarily due to an increase in annual bonuses paid in common units of approximately $7.0 million and the cancellation of our Performance Awards during the year ended March 31, 2019. This increase was partially offset by a decrease specifically related to our Service Awards of approximately $4.2 million, which was primarily due to the vesting of Service Awards with higher grant date fair values during the year ended March 31, 2018. For further discussion of the Service Awards, see Note 10 to our consolidated financial statements included in this Annual Report. The increase in equity-based compensation was primarily offset by a decrease in legal expenses.

Depreciation and Amortization Expense. The decrease was due primarily to certain information technology equipment which was fully depreciated at the end of March 31, 2018.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2019, we sold our 50% interest in Victory Propane and as consideration we received a promissory note from Victory Propane. We discounted the promissory note to its net present value and recorded a loss of $0.9 million (see Note 13 to our consolidated financial statements included in this Annual Report).

Equity in Earnings of Unconsolidated Entities

The decrease of $5.0 million during the year ended March 31, 2019 was due primarily to the sale of our investments in Glass Mountain and E Energy Adams, LLC. On December 22, 2017, we sold our previously held 50% interest in Glass Mountain and on May 3, 2018, we sold our previously held 20% interest in E Energy Adams, LLC. These decreases were partially offset by earnings from our 50% interest in a water services company that we acquired as part of an acquisition in August 2018. See Note 2 and Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

Interest Expense

Interest expense includes interest charged on the revolving credit facilities, senior secured notes, and senior unsecured notes, as well as amortization of debt issuance costs, letter of credit fees, interest on equipment financing notes, and accretion of interest on non-interest bearing debt obligations. The decrease of $34.4 million during the year ended March 31, 2019 was partially due to the repurchase of all senior secured notes on December 29, 2017. We also repurchased $84.1 million of the 2023 Notes (as defined herein) and $110.9 million of the 2025 Notes (as defined herein) during the year ended March 31, 2018. Also contributing to the decrease is the October 16, 2018 redemption of the remaining outstanding 2021 Notes (as defined herein) and the March 15, 2019 redemption of the remaining outstanding 2019 Notes. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

Loss on Early Extinguishment of Liabilities, Net

During the year ended March 31, 2019, the net loss (inclusive of debt issuance costs written off) relates to the early extinguishment of a portion of the outstanding senior unsecured notes and the redemption of the 2019 Notes and 2021 Notes. During the year ended March 31, 2018, the net loss (inclusive of debt issuance costs written off) relates to the early extinguishment of all of the senior secured notes and a portion of the senior unsecured notes. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

Other (Expense) Income, Net

The following table summarizes the components of other (expense) income, net for the periods indicated:

	Year Ended March 31,	
	2019	2018
	(in thousands)	
Interest income (1)	$ 5,199	$ 6,297
Gavilon legal matter settlement (2)	(34,788)	—
Other (3)	(357)	656
Other (expense) income, net	$ (29,946)	$ 6,953

(1) During the year ended March 31, 2019, this relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility that is utilized by a third party. During the year ended March 31, 2018, this relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility that is utilized by a third party and to a loan receivable from Victory Propane (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion).

(2) Represents the accrual for the estimated cost of the settlement of the Gavilon legal matter (see Note 9 to our consolidated financial statements included in this Annual Report for a further discussion).

(3) During the year ended March 31, 2019, this relates primarily to unrealized losses on marketable securities. During the year ended March 31, 2018, this relates primarily to proceeds from a litigation settlement.

Income Tax Expense

Income tax expense was $1.2 million during the year ended March 31, 2019, compared to income tax expense of $1.4 million during the year ended March 31, 2018. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Noncontrolling Interests - Redeemable and Non-redeemable

Noncontrolling interests represent the portion of certain consolidated subsidiaries that are owned by third parties. The increase in the noncontrolling interest loss of $21.9 million during the year ended March 31, 2019 was due primarily to a loss from operations of the Sawtooth joint venture, in which we sold a 28.5% interest in March 2018.

Segment Operating Results for the Years Ended March 31, 2018 and 2017

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Crude Oil Logistics

The following table summarizes the operating results of our Crude Oil Logistics segment for the periods indicated:

	Year Ended March 31,		
	2018	2017	Change
	(in thousands, except per barrel amounts)		
Revenues:			
Crude oil sales	$ 2,151,203	$ 1,603,667	$ 547,536
Crude oil transportation and other	122,786	70,027	52,759
Total revenues (1)	2,273,989	1,673,694	600,295
Expenses:			
Cost of sales-excluding impact of derivatives	2,120,640	1,573,246	547,394
Cost of sales-derivative loss	7,021	5,579	1,442
Operating expenses	47,846	41,535	6,311
General and administrative expenses	6,584	5,961	623
Depreciation and amortization expense	80,387	54,144	26,243
(Gain) loss on disposal or impairment of assets, net	(111,393)	10,704	(122,097)
Total expenses	2,151,085	1,691,169	459,916
Segment operating income (loss)	$ 122,904	$ (17,475)	$ 140,379
Crude oil sold (barrels)	39,626	34,212	5,414
Crude oil transported on owned pipelines (barrels)	33,454	6,365	27,089
Crude oil storage capacity - owned and leased (barrels) (2)	6,159	7,024	(865)
Crude oil storage capacity leased to third parties (barrels) (2)	2,641	3,717	(1,076)
Crude oil inventory (barrels) (2)	1,219	2,844	(1,625)
Crude oil sold ($/barrel)	$ 54.288	$ 46.874	$ 7.414
Cost per crude oil sold ($/barrel)	$ 53.694	$ 46.148	$ 7.546
Crude oil product margin ($/barrel)	$ 0.594	$ 0.726	$ (0.132)

(1) Revenues include $13.9 million and $6.8 million of intersegment sales during the years endedMarch 31, 2018 and 2017, respectively, that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Crude Oil Sales Revenues. The increase was due primarily to an increase in crude oil prices and sales volumes during the year ended March 31, 2018, compared to the year ended March 31, 2017. This segment continued to be impacted by competition and low margins in the majority of the basins across the United States and we continue to market crude volumes in these basins to support our various pipeline, terminal and transportation assets. Additionally, we bear the cost of certain minimum volume commitments on third-party crude oil pipelines in various basins which are currently not profitable.

Crude Oil Transportation and Other Revenues. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 which increased revenues by $55.0 million during the year ended March 31, 2018, compared to the year ended March 31, 2017. The increase was also due to increased volumes related to production growth in the DJ Basin. During the year ended March 31, 2018, approximately 33.5 million barrels of crude oil were transported on the Grand Mesa Pipeline, which averaged approximately 92,000 barrels per day and financial volumes averaged approximately 96,000 barrels per day (volume amounts are from both internal and external parties). Higher revenues in our trucking operations during the year ended March 31, 2018 were due primarily to increased demand for transportation services, compared to the year ended March 31, 2017, and were partially offset by the flattening of the contango curve for crude oil (a condition in which forward crude oil prices are greater than spot prices) during the year ended March 31, 2018, compared to the year ended March 31, 2017.

Cost of Sales-Excluding Impact of Derivatives. The increase was due primarily to an increase in crude oil prices during the year ended March 31, 2018, compared to the year ended March 31, 2017.

Cost of Sales-Derivatives. Our cost of sales during the year ended March 31, 2018 included $4.2 million of net realized losses on derivatives and $2.8 million of net unrealized losses on derivatives. Our cost of sales during the year ended March 31, 2017 included $7.1 million of net realized losses on derivatives and $1.5 million of net unrealized gains on derivatives.

Operating and General and Administrative Expenses . The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 which increased expenses by $8.0 million during the year ended March 31, 2018, compared to the year ended March 31, 2017. This increase was partially offset by lower repair and maintenance expense associated with having a newer fleet of barges and a smaller fleet of trucks, as well as the timing of repairs, and lower property taxes due to decreased inventory.

Depreciation and Amortization Expense. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 which increased depreciation and amortization expense by $23.0 million during the year ended March 31, 2018, compared to the year ended March 31, 2017. Also contributing to the increase was higher depreciation expense related to other capital projects being placed into service.

(Gain) Loss on Disposal or Impairment of Assets, Net . During the year ended March 31, 2018, we recorded a gain of $108.6 million on the sale of our previously held 50% interest in Glass Mountain (see Note 16 to our consolidated financial statements included in this Annual Report). In addition, we recorded a net gain of $2.8 million on the sales of excess pipe and certain other assets. During the year ended March 31, 2017, we recorded a net loss of $6.5 million on the sales of certain assets and a loss of $4.2 million due to the write-down of certain other assets.

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Water Solutions

The following table summarizes the operating results of our Water Solutions segment for the periods indicated:

	Year Ended March 31, 2018	Year Ended March 31, 2017	Change
	(in thousands, except per barrel and per day amounts)		
Revenues:			
Wastewater disposal service fees	$ 149,114	$ 110,049	$ 39,065
Sale of recovered hydrocarbons	58,948	31,103	27,845
Other service revenues	21,077	18,449	2,628
Total revenues	229,139	159,601	69,538
Expenses:			
Cost of sales-excluding impact of derivatives	2,150	2,071	79
Cost of sales-derivative loss	17,195	1,997	15,198
Operating expenses	105,200	85,562	19,638
General and administrative expenses	2,623	2,469	154
Depreciation and amortization expense	98,623	101,758	(3,135)
Loss (gain) on disposal or impairment of assets, net	6,863	(85,560)	92,423
Revaluation of liabilities	20,716	6,717	13,999
Total expenses	253,370	115,014	138,356
Segment operating (loss) income	$ (24,231)	$ 44,587	$ (68,818)
Wastewater processed (barrels per day)			
Permian Basin	289,360	184,702	104,658
Eagle Ford Basin	235,713	208,649	27,064
DJ Basin	113,771	68,253	45,518
Other Basins	68,466	40,185	28,281
Total	707,310	501,789	205,521
Solids processed (barrels per day)	5,662	3,056	2,606
Skim oil sold (barrels per day)	3,210	1,989	1,221
Service fees for wastewater processed ($/barrel)	$ 0.58	$ 0.60	$ (0.02)
Recovered hydrocarbons for wastewater processed ($/barrel)	$ 0.23	$ 0.17	$ 0.06
Operating expenses for wastewater processed ($/barrel)	$ 0.41	$ 0.47	$ (0.06)

Wastewater Disposal Service Fee Revenues. The increase was due primarily to an increase in the volume of wastewater processed, partially offset by higher volumes in areas with lower fees. We continue to benefit from the increased rig counts as compared to the prior year in the basins in which we operate, particularly in the Permian Basin.

Recovered Hydrocarbon Revenues. The increase was due primarily to an increase in the volume of wastewater processed, an increase in the amount of hydrocarbons per barrel of wastewater processed and an increase in crude oil prices.

Other Service Revenues. The increase was due primarily to an increase in solids disposal revenues and water pipeline revenues due to increased volumes. These increases were partially offset by a decrease in freshwater revenues due to the sale of Grassland Water Solutions, LLC (“Grassland”) in November 2016 (see below discussion of the loss on the sale of Grassland).

Cost of Sales-Excluding Impact of Derivatives . Cost of Sales-Excluding Impact of Derivatives was consistent between the current year and prior year.

Cost of Sales-Derivatives. We enter into derivatives in our Water Solutions segment to protect against the risk of a decline in the market price of the hydrocarbons we expect to recover when processing the wastewater and selling the skim oil. Our cost of sales during the year ended March 31, 2018 included $13.7 million of net unrealized losses on derivatives and $3.5 million of net realized losses on derivatives. Our cost of sales during the year ended March 31, 2017 included $4.1 million of net realized losses on derivatives and the reversal of $2.1 million of net unrealized losses on derivatives at March 31, 2016 as there were no open derivatives at March 31, 2017.

Operating and General and Administrative Expenses . The increase was due primarily to higher costs of operations of water disposal wells due to higher volumes processed, partially offset by cost reduction efforts. Due to the higher volumes processed, our cost per barrel has decreased, as shown in the table above.

Depreciation and Amortization Expense . The decrease was due primarily to lower amortization expense from the write-off of an intangible asset during the year ended March 31, 2017 as well as certain intangible assets being fully amortized during the year ended March 31, 2017, partially offset by acquisitions and developed facilities (see Note 7 to our consolidated financial statements included in this Annual Report).

Loss (Gain) on Disposal or Impairment of Assets, Net . During the year ended March 31, 2018, we recorded a loss of $8.2 million on the disposals of certain assets, partially offset by a gain of $1.3 million for the termination of a non-compete agreement, which included the carrying value of the non-compete agreement intangible asset that was written off (see Note 7 to our consolidated financial statements included in this Annual Report).

During the year ended March 31, 2017, we recorded:

- an adjustment of $124.7 million to the previously recorded $380.2 million estimated goodwill impairment charge recorded during the three months ended March 31, 2016 (see Note 6 to our consolidated financial statements included in this Annual Report);
- a write-off of $5.2 million related to the value of an indefinite-lived trade name intangible asset in conjunction with finalizing our goodwill impairment analysis (see Note 7 to our consolidated financial statements included in this Annual Report);
- a loss of $22.7 million related to the termination of the development agreement, which included the carrying value of the development agreement asset that was written off (see Note 16 to our consolidated financial statements included in this Annual Report);
- an impairment charge of $1.7 million to write down a loan receivable in June 2016 (see Note 13 to our consolidated financial statements included in this Annual Report); and
- a loss of $9.5 million on the sales of certain assets, including the sale of Grassland (see Note 13 to our consolidated financial statements included in this Annual Report for a discussion of the sale of Grassland).

Revaluation of Liabilities. The revaluation of liabilities represents the change in the valuation of our contingent consideration liabilities related to royalty agreements acquired as part of certain business combinations during the year ended March 31, 2017. The increase in the expense during the year ended March 31, 2018 was due primarily to higher actual and expected production from new customers, resulting in an increase to the expected future royalty payment.

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Liquids

The following table summarizes the operating results of our Liquids segment for the periods indicated:

	Year Ended March 31, 2018	Year Ended March 31, 2017	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$ 1,203,486	$ 807,172	$ 396,314
Cost of sales-excluding impact of derivatives	1,165,414	772,871	392,543
Cost of sales-derivative gain	(5,577)	(2,633)	(2,944)
Product margin	43,649	36,934	6,715
Butane sales:			
Revenues (1)	562,066	391,265	170,801
Cost of sales-excluding impact of derivatives	535,017	354,132	180,885
Cost of sales-derivative loss	19,616	7,863	11,753
Product margin	7,433	29,270	(21,837)
Other product sales:			
Revenues (1)	432,570	308,031	124,539
Cost of sales-excluding impact of derivatives	414,980	290,495	124,485
Cost of sales-derivative gain	(173)	(1,477)	1,304
Product margin	17,763	19,013	(1,250)
Other revenues:			
Revenues (1)	22,548	32,648	(10,100)
Cost of sales	3,930	12,893	(8,963)
Product margin	18,618	19,755	(1,137)
Expenses:			
Operating expenses	32,792	37,634	(4,842)
General and administrative expenses	5,331	4,831	500
Depreciation and amortization expense	24,937	19,163	5,774
Loss on disposal or impairment of assets, net	117,516	92	117,424
Total expenses	180,576	61,720	118,856
Segment operating (loss) income	$ (93,113)	$ 43,252	$ (136,365)
Liquids storage capacity - owned and leased (gallons) (2)	438,968	358,537	80,431
Propane sold (gallons)	1,361,173	1,267,076	94,097
Propane sold ($/gallon)	$ 0.884	$ 0.637	$ 0.247
Cost per propane sold ($/gallon)	$ 0.852	$ 0.608	$ 0.244
Propane product margin ($/gallon)	$ 0.032	$ 0.029	$ 0.003
Propane inventory (gallons) (2)	48,928	48,351	577
Propane storage capacity leased to third parties (gallons) (2)	29,662	33,495	(3,833)
Butane sold (gallons)	544,750	456,586	88,164
Butane sold ($/gallon)	$ 1.032	$ 0.857	$ 0.175
Cost per butane sold ($/gallon)	$ 1.018	$ 0.793	$ 0.225
Butane product margin ($/gallon)	$ 0.014	$ 0.064	$ (0.050)
Butane inventory (gallons) (2)	15,385	9,438	5,947
Butane storage capacity leased to third parties (gallons) (2)	51,660	80,346	(28,686)
Other products sold (gallons)	400,405	343,365	57,040
Other products sold ($/gallon)	$ 1.080	$ 0.897	$ 0.183
Cost per other products sold ($/gallon)	$ 1.036	$ 0.842	$ 0.194
Other products product margin ($/gallon)	$ 0.044	$ 0.055	$ (0.011)
Other products inventory (gallons) (2)	5,822	6,426	(604)

(1) Revenues include $4.7 million and $1.9 million of intersegment sales during the years endedMarch 31, 2018 and 2017, respectively, that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Propane Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due to higher commodity prices, and increased volume due to a new long-term marketing agreement.

Cost of Sales-Derivatives. Our cost of wholesale propane sales was reduced by $1.0 million and $1.5 million of net unrealized gains on derivatives for the years ended March 31, 2018 and 2017, respectively. Additionally, our cost of wholesale propane sales was reduced by $4.6 million and $1.1 million of net realized gains on derivatives for the years ended March 31, 2018 and 2017, respectively.

Product margins per gallon of propane sold were higher during the year ended March 31, 2018 than during the year ended March 31, 2017 facilitated by stronger winter demand.

Butane Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were primarily due to higher commodity prices.

Cost of Sales-Derivatives. Our cost of butane sales was increased by $0.5 million and $2.0 million of net unrealized losses on derivatives for the years ended March 31, 2018 and 2017, respectively. Additionally, our cost of butane sales was increased by $19.1 million and $5.9 million of net realized losses on derivatives for the years ended March 31, 2018 and 2017, respectively.

Product margins per gallon of butane sold were lower during the year ended March 31, 2018 than during the year ended March 31, 2017 due primarily to the overall competitive nature of the market as well as higher than anticipated unrecovered railcar fleet costs.

Other Products Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due primarily to a new long-term marketing agreement. Also, volumes have increased with the addition of the new Port Hudson terminal.

Cost of Sales-Derivatives. Our cost of sales of other products was reduced by $0.1 million and $0.2 million of net unrealized gains on derivatives for the years ended March 31, 2018 and 2017, respectively. Additionally, our cost of other products was reduced by $0.1 million and $1.3 million of net realized gains on derivatives for the years ended March 31, 2018 and 2017, respectively.

Product margin decrease during the year ended March 31, 2018 was due primarily to an increase in unrecovered railcar fleet costs.

Other Revenues. This revenue includes storage, terminaling and transportation services income. The decrease was due primarily to reduced transportation services and increased storage capacity available in the market.

Operating and General and Administrative Expenses. The decrease was due primarily to a reduction in incentive compensation that was paid in common units and reflected in “Corporate and Other”. Repair and maintenance expense was lower across most terminals due to tightly managing and prioritizing critical repairs.

Depreciation and Amortization Expense. The increase was due primarily to the acquisition of two liquids facilities during the previous fiscal year.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded a goodwill impairment charge of $116.9 million related to our salt dome storage facility in Utah due to the decreased demand for natural gas liquid storage and resulting decline in revenues and earnings as compared to actual and projected results of prior and future periods (see Note 6 to our consolidated financial statements included in this Annual Report). During the years ended March 31, 2018 and 2017, we recorded a net loss of $0.6 million and $0.1 million, respectively, related to the retirement of assets.

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Refined Products and Renewables

The following table summarizes the operating results of our Refined Products and Renewables segment for the periods indicated.

	Year Ended March 31,		
	2018	2017	Change
	(in thousands, except per barrel amounts)		
Refined products sales:			
Revenues (1)	$ 11,827,222	$ 8,884,976	$ 2,942,246
Cost of sales-excluding impact of derivatives	11,709,786	8,732,312	2,977,474
Cost of sales-derivative loss	77,055	43,358	33,697
Product margin	40,381	109,306	(68,925)
Renewables sales:			
Revenues	373,669	447,232	(73,563)
Cost of sales-excluding impact of derivatives	362,457	443,229	(80,772)
Cost of sales-derivative loss	1,467	1,291	176
Product margin	9,745	2,712	7,033
Service fees and other revenues	300	10,963	(10,663)
Expenses:			
Operating expenses	14,057	23,177	(9,120)
General and administrative expenses	8,433	9,821	(1,388)
Depreciation and amortization expense	1,294	1,562	(268)
Gain on disposal or impairment of assets, net	(30,098)	(134,125)	104,027
Total income, net	(6,314)	(99,565)	93,251
Segment operating income	$ 56,740	$ 222,546	$ (165,806)
Gasoline sold (barrels)	108,427	91,004	17,423
Diesel sold (barrels)	56,020	49,817	6,203
Ethanol sold (barrels)	3,438	4,605	(1,167)
Biodiesel sold (barrels)	2,079	2,413	(334)
Refined products and renewables storage capacity - leased (barrels) (2)	9,911	9,419	492
Refined products and renewables storage capacity sub-leased to third parties (barrels) (2)	1,068	1,043	25
Gasoline inventory (barrels) (2)	3,367	2,993	374
Diesel inventory (barrels) (2)	1,419	1,464	(45)
Ethanol inventory (barrels) (2)	701	727	(26)
Biodiesel inventory (barrels) (2)	261	471	(210)
Refined products sold ($/barrel)	$ 71.921	$ 63.094	$ 8.827
Cost per refined products sold ($/barrel)	$ 71.676	$ 62.318	$ 9.358
Refined products product margin ($/barrel)	$ 0.245	$ 0.776	$ (0.531)
Renewable products sold ($/barrel)	$ 67.730	$ 63.726	$ 4.004
Cost per renewable products sold ($/barrel)	$ 65.964	$ 63.340	$ 2.624
Renewable products product margin ($/barrel)	$ 1.766	$ 0.386	$ 1.380

(1) Revenues include $0.3 million and $0.5 million of intersegment sales during the years endedMarch 31, 2018 and 2017, respectively, that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Refined Products Revenues and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due to an increase in refined products prices and increased volumes. The increased volumes were due primarily to additional pipeline capacity rights purchased during the year ended March 31, 2017, an expansion of our refined products operations and the continued demand for motor fuels. The decrease in margin was due primarily to negative impact of the continued decline in gasoline line space values on the Colonial Pipeline, discretionary terminal volume profitability and line space sales during the year ended March 31, 2018, compared to the year ended March 31, 2017. The average value of line space was approximately negative $0.007 per gallon for the year ended March 31, 2018, compared to an average value of approximately $0.009 per gallon for the year ended March 31, 2017.

Refined Products Cost of Sales-Derivatives. The margins for both the years ended March 31, 2018 and 2017 were negatively impacted by losses of $77.1 million and $43.4 million, respectively, from our risk management activities. These losses were due primarily to increasing future prices.

Renewables Revenues and Cost of Sales-Excluding Impact of Derivatives. The decreases in revenues and cost of sales-excluding impact of derivatives were due primarily to decreased volumes from the loss of a marketing contract with E Energy Adams, LLC in December 2017, partially offset by an increase in renewables prices. The margin was higher during the year ended March 31, 2018 due primarily to favorable biodiesel margins resulting from the biodiesel tax credit being reinstated in February 2018 for the 2017 calendar year.

Renewables Cost of Sales-Derivatives. The margins for both the years ended March 31, 2018 and 2017 were negatively impacted by losses of $1.5 million and $1.3 million, respectively, from our risk management activities. These losses were due primarily to the weakness in the price of renewable identification numbers and increasing future prices.

Service Fees and Other Revenues, Operating Expenses, General and Administrative Expenses. The decreases were due primarily to the expiration of a transition services agreement in October 2016 related to the sale of the general partner interest in TLP in February 2016 whereby we were reimbursed for certain expenses incurred on behalf of a third party.

Depreciation and Amortization Expense. The decrease was due primarily to certain assets being fully depreciated during the year ended March 31, 2017.

Gain on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded $30.1 million of the deferred gain from the sale of the general partner interest in TLP in February 2016 (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion). In addition, we recorded a net loss of less than $0.1 million on the disposal of certain assets.

During the year ended March 31, 2017, we recorded:

- a $104.1 million gain from the sale of all of the TLP units we owned (see Note 16 to our consolidated financial statements included in this Annual Report for a further discussion);
- $30.1 million of the deferred gain from the sale of the general partner in interest in TLP in February 2016 (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion); and
- a loss of $0.1 million on the sales of certain assets.

Corporate and Other

The operating loss within "Corporate and Other" includes the following components for the periods indicated:

	Year Ended March 31, 2018	Year Ended March 31, 2017	Change
	(in thousands)		
Other revenues:			
Revenues	$ 1,174	$ 844	$ 330
Cost of sales	530	400	130
Margin	644	444	200
Expenses:			
Operating expenses	1,173	1,095	78
General and administrative expenses	75,158	82,723	(7,565)
Depreciation and amortization expense	3,779	3,612	167
Loss (gain) on disposal or impairment of assets, net	8	(1)	9
Total expenses	80,118	87,429	(7,311)
Operating loss	$ (79,474)	$ (86,985)	$ 7,511

General and Administrative Expenses. The decrease for the year ended March 31, 2018 was due primarily to a decrease in equity-based compensation expense related to service awards. The expense related to service awards was $16.2 million for the year ended March 31, 2018, compared to $37.2 million for the year ended March 31, 2017. The increase in expense in the prior fiscal year was due to the cancellation of awards which accelerated the expense reporting. In addition, during the first quarter of the prior fiscal year, the expense for the service awards was accounted for under the liability method and due to an increase in our unit price during that period, we recorded an increase in equity-based compensation expense. Also, see Note 10 to our consolidated financial statements included in this Annual Report for a further discussion of our equity-based compensation. The decrease from equity-based compensation was partially offset by increases in legal expenses and workmen's compensation.

Equity in Earnings of Unconsolidated Entities

The increase of $3.7 million during the year ended March 31, 2018 was due primarily to increased earnings related to our investment in Glass Mountain. On December 22, 2017, we sold our previously held 50% interest in Glass Mountain. See Note 16 to our consolidated financial statements included in this Annual Report for a further discussion.

Interest Expense

The increase of $49.2 million during the year ended March 31, 2018 was due primarily to the issuance of the 2023 Notes and 2025 Notes which have higher interest rates than the revolving credit facility. This was offset by lower interest expense on the revolving credit facility as our average balance outstanding decreased from $1.7 billion for the year ended March 31, 2017 to $1.0 billion for the year ended March 31, 2018.

(Loss) Gain on Early Extinguishment of Liabilities, Net

The following table summarizes the components of (loss) gain on early extinguishment of liabilities, net for the periods indicated:

	Year Ended March 31,	
	2018	2017
	(in thousands)	
Early extinguishment of long-term debt (1)	$ (23,201)	$ 6,922
Release of contingent consideration liabilities (2)	—	22,278
Write-off deferred debt issuance costs (3)	—	(4,473)
(Loss) gain on early extinguishment of liabilities, net	$ (23,201)	$ 24,727

(1) During the year ended March 31, 2018, the net loss (inclusive of debt issuance costs written off) relates to the early extinguishment of all of the senior secured notes and a portion of the senior unsecured notes. During the year ended March 31, 2017, the net gain (inclusive of debt issuance costs written off) relates to the early extinguishment of a portion of the senior unsecured notes and certain equipment loans. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

(2) Relates to the release of certain contingent consideration liabilities in conjunction with the termination of the development agreement in June 2016 (see Note 16 to our consolidated financial statements included in this Annual Report for a further discussion). Also, during the year ended March 31, 2017, we acquired certain parcels of land on which one of our water solutions facilities is located and recorded a gain on the release of certain contingent consideration liabilities as the royalty agreement was terminated.

(3) Relates to the write off of certain deferred debt issuance costs in connection with the amendment and restatement of the Credit Agreement (as defined herein) (see Note 7 to our consolidated financial statements included in this Annual Report for a further discussion).

Other Income, Net

The following table summarizes the components of other income, net for the periods indicated:

	Year Ended March 31,	
	2018	2017
	(in thousands)	
Interest income (1)	$ 6,297	$ 7,553
Termination of storage sublease agreement (2)	—	16,205
Other (3)	656	2,854
Other income, net	$ 6,953	$ 26,612

(1) During the year ended March 31, 2018, this relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility that is utilized by a third party and to a loan receivable from Victory Propane (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion). During the year ended March 31, 2017, this relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility that is utilized by a third party and to loan receivables from Victory Propane and Grassland (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion). On June 3, 2016, we acquired the remaining 65% ownership interest in Grassland and all interest income on the receivable from Grassland has been eliminated in consolidation subsequent to that date.

(2) Represents a gain from the termination of a storage sublease agreement (see Note 16 to our consolidated financial statements included in this Annual Report for a further discussion).

(3) During the year ended March 31, 2018, this relates primarily to proceeds from a litigation settlement. During the year ended March 31, 2017, this relates primarily to a distribution from TLP pursuant to the agreement to sell all of the TLP common units we owned in April 2016, a gain on insurance settlement related to business interruption insurance coverage on a facility in our Water Solutions segment, a payment received related to a contract termination and another party’s share of the profits and losses generated from a joint crude oil marketing arrangement.

Income Tax Expense

Income tax expense was $1.4 million during the year ended March 31, 2018, compared to income tax expense of $1.9 million during the year ended March 31, 2017. The decrease in income tax expense was due primarily to a lower state franchise tax liability in Texas as well as a lower Canadian tax liability from our taxable corporate subsidiaries in Canada. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Noncontrolling Interests - Redeemable and Non-redeemable

The decrease of $5.6 million during the year ended March 31, 2018 was due primarily to adjustments related to noncontrolling interests during the year ended March 31, 2017.

Non-GAAP Financial Measures

In addition to financial results reported in accordance with accounting principles generally accepted in the United States ("GAAP"), we have provided the non-GAAP financial measures of EBITDA and Adjusted EBITDA. These non-GAAP financial measures are not intended to be a substitute for those reported in accordance with GAAP. These measures may be different from non-GAAP financial measures used by other entities, even when similar terms are used to identify such measures.

We define EBITDA as net income (loss) attributable to NGL Energy Partners LP, plus interest expense, income tax expense (benefit), and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA excluding net unrealized gains and losses on derivatives, lower of cost or market adjustments, gains and losses on disposal or impairment of assets, gains and losses on early extinguishment of liabilities, revaluation of investments, equity-based compensation expense, acquisition expense, revaluation of liabilities, certain legal settlements and other. We also include in Adjusted EBITDA certain inventory valuation adjustments related to our Refined Products and Renewables segment, as discussed below. EBITDA and Adjusted EBITDA should not be considered alternatives to net income (loss), (loss) income from continuing operations before income taxes , cash flows from operating activities, or any other measure of financial performance calculated in accordance with GAAP, as those items are used to measure operating performance, liquidity or the ability to service debt obligations. We believe that EBITDA provides additional information to investors for evaluating our ability to make quarterly distributions to our unitholders and is presented solely as a supplemental measure. We believe that Adjusted EBITDA provides additional information to investors for evaluating our financial performance without regard to our financing methods, capital structure and historical cost basis. Further, EBITDA and Adjusted EBITDA, as we define them, may not be comparable to EBITDA, Adjusted EBITDA, or similarly titled measures used by other entities.

Other than for our Refined Products and Renewables segment, for purposes of our Adjusted EBITDA calculation, we make a distinction between realized and unrealized gains and losses on derivatives. During the period when a derivative contract is open, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record a realized gain or loss. We do not draw such a distinction between realized and unrealized gains and losses on derivatives of our Refined Products and Renewables segment. The primary hedging strategy of our Refined Products and Renewables segment is to hedge against the risk of declines in the value of inventory over the course of the contract cycle, and many of the hedges are six months to one year in duration at inception. The "inventory valuation adjustment" row in the reconciliation table reflects the difference between the market value of the inventory of our Refined Products and Renewables segment at the balance sheet date and its cost, adjusted for the impact of seasonal market movements related to our base inventory and the related hedge. We include this in Adjusted EBITDA because the unrealized gains and losses associated with derivative contracts associated with the inventory of this segment, which are intended primarily to hedge inventory holding risk and are included in net income, also affect Adjusted EBITDA.

The following table reconciles net income (loss) to EBITDA and Adjusted EBITDA:

	Year Ended March 31,		
	2019	2018	2017
		(in thousands)	
Net income (loss)	$ 339,395	$ (69,605)	$ 143,874
Less: Net loss (income) attributable to noncontrolling interests	20,206	(240)	(6,832)
Less: Net loss (income) attributable to redeemable noncontrolling interests	446	(1,030)	—
Net income (loss) attributable to NGL Energy Partners LP	360,047	(70,875)	137,042
Interest expense	164,879	199,747	150,504
Income tax expense	2,222	1,458	1,939
Depreciation and amortization	224,547	266,525	238,583
EBITDA	751,695	396,855	528,068
Net unrealized (gains) losses on derivatives	(17,296)	15,883	(3,338)
Inventory valuation adjustment (1)	(5,203)	11,033	7,368
Lower of cost or market adjustments	2,695	399	(1,283)
Gain on disposal or impairment of assets, net	(393,554)	(105,313)	(209,213)
Loss (gain) on early extinguishment of liabilities, net	12,340	23,201	(24,727)
Revaluation of investments	—	—	14,365
Equity-based compensation expense (2)	41,367	35,241	53,102
Acquisition expense (3)	9,780	263	1,771
Revaluation of liabilities (4)	(5,373)	20,607	12,761
Gavilon legal matter settlement (5)	34,788	—	—
Other (6)	9,203	10,081	2,443
Adjusted EBITDA	$ 440,442	$ 408,250	$ 381,317

(1) Amount reflects the difference between the market value of the inventory of our Refined Products and Renewables segment at the balance sheet date and its cost, adjusted for the impact of seasonal market movements related to our base inventory and the related hedge. See "Non-GAAP Financial Measures" section above for a further discussion.

(2) Equity-based compensation expense in the table above may differ from equity-based compensation expense reported in Note 10 to our consolidated financial statements included in this Annual Report. Amounts reported in the table above include expense accruals for bonuses expected to be paid in common units, whereas the amounts reported in Note 10 to our consolidated financial statements only include expenses associated with equity-based awards that have been formally granted.

(3) Amounts represent expenses we incurred related to legal and advisory costs associated with acquisitions, including amounts accrued related to the LCT Capital, LLC legal matter (see Note 9 to our consolidated financial statements included in this Annual Report), partially offset by reimbursement for certain legal costs incurred in prior periods.

(4) Amounts represent the non-cash valuation adjustment of contingent consideration liabilities, offset by the cash payments, related to royalty agreements acquired as part of acquisitions in our Water Solutions segment.

(5) Represents the accrual for the estimated cost of the settlement of the Gavilon legal matter (see Note 9 to our consolidated financial statements included in this Annual Report). We have excluded this amount from Adjusted EBITDA as it relates to transactions that occurred prior to our acquisition of Gavilon LLC in December 2013.

(6) The amount for the year ended March 31, 2019 represents non-cash operating expenses related to our Grand Mesa Pipeline, unrealized losses on marketable securities and accretion expense for asset retirement obligations. The amount for the year ended March 31, 2018 represents non-cash operating expenses related to our Grand Mesa Pipeline, an adjustment to inventory related to prior periods and accretion expense for asset retirement obligations. The amount for the year ended March 31, 2017 represents non-cash operating expenses related to our Grand Mesa Pipeline and accretion expense for asset retirement obligations.

The following tables reconcile depreciation and amortization amounts per the EBITDA table above to depreciation and amortization amounts reported in our consolidated statements of operations and consolidated statements of cash flows for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Reconciliation to consolidated statements of operations:			
Depreciation and amortization per EBITDA table	$ 224,547	$ 266,525	$ 238,583
Intangible asset amortization recorded to cost of sales	(5,619)	(6,099)	(6,828)
Depreciation and amortization of unconsolidated entities	(331)	(8,706)	(11,869)
Depreciation and amortization attributable to noncontrolling interests	2,921	497	2,913
Depreciation and amortization attributable to discontinued operations	(8,658)	(43,197)	(42,560)
Depreciation and amortization per consolidated statements of operations	$ 212,860	$ 209,020	$ 180,239
Reconciliation to consolidated statements of cash flows:			
Depreciation and amortization per EBITDA table	$ 224,547	$ 266,525	$ 238,583
Amortization of debt issuance costs recorded to interest expense	9,215	10,619	7,762
Depreciation and amortization of unconsolidated entities	(331)	(8,706)	(11,869)
Depreciation and amortization attributable to noncontrolling interests	2,921	497	2,913
Depreciation and amortization attributable to discontinued operations	(8,658)	(43,197)	(42,560)
Depreciation and amortization per consolidated statements of cash flows	$ 227,694	$ 225,738	$ 194,829

The following table reconciles interest expense per the EBITDA table above to interest expense reported in our consolidated statements of operations for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Interest expense per EBITDA table	$ 164,879	$ 199,747	$ 150,504
Interest expense attributable to unconsolidated entities	(14)	(149)	—
Interest expense attributable to discontinued operations	(139)	(450)	(510)
Interest expense per consolidated statements of operations	$ 164,726	$ 199,148	$ 149,994

The following table summarizes additional amounts attributable to discontinued operations in the EBITDA table above for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Income tax expense	$ 988	$ 104	$ 6
Net unrealized losses on derivatives	$ 78	$ —	$ 47
Gain on disposal or impairment of assets, net	$ (408,964)	$ (89,290)	$ (295)

The following tables reconcile operating income (loss) to Adjusted EBITDA by segment for the periods indicated. We have revised certain prior period information to be consistent with the calculation method used in the current fiscal year.

	Year Ended March 31, 2019						
	Crude Oil Logistics	Water Solutions	Liquids	Refined Products and Renewables	Corporate and Other	Discontinued Operations	Consolidated
	(in thousands)						
Operating (loss) income	$ (7,379)	$ 210,525	$ (2,910)	$ 27,459	$ (85,706)	$ —	$ 141,989
Depreciation and amortization	74,165	108,162	25,997	1,518	3,018	—	212,860
Amortization recorded to cost of sales	80	—	147	5,392	—	—	5,619
Net unrealized gains on derivatives	(1,725)	(15,521)	(129)	—	—	—	(17,375)
Inventory valuation adjustment	—	—	—	(5,203)	—	—	(5,203)
Lower of cost or market adjustments	—	—	1,004	1,691	—	—	2,695
Loss (gain) on disposal or impairment of assets, net	107,424	(138,204)	67,213	(3,026)	889	—	34,296
Equity-based compensation expense	—	—	—	—	41,367	—	41,367
Acquisition expense	—	3,490	161	—	6,176	—	9,827
Other income (expense), net	21	(1)	68	74	(30,108)	—	(29,946)
Adjusted EBITDA attributable to unconsolidated entities	—	2,396	6	475	—	—	2,877
Adjusted EBITDA attributable to noncontrolling interest	—	(166)	(1,481)	—	—	—	(1,647)
Revaluation of liabilities	—	(5,373)	—	—	—	—	(5,373)
Gavilon legal matter settlement	—	—	—	—	34,788	—	34,788
Other	8,274	436	66	427	—	—	9,203
Discontinued operations	—	—	—	—	—	4,465	4,465
Adjusted EBITDA	$ 180,860	$ 165,744	$ 90,142	$ 28,807	$ (29,576)	$ 4,465	$ 440,442

	Year Ended March 31, 2018						
	Crude Oil Logistics	Water Solutions	Liquids	Refined Products and Renewables	Corporate and Other	Discontinued Operations	Consolidated
	(in thousands)						
Operating income (loss)	$ 122,904	$ (24,231)	$ (93,113)	$ 56,740	$ (79,474)	$ —	$ (17,174)
Depreciation and amortization	80,387	98,623	24,937	1,294	3,779	—	209,020
Amortization recorded to cost of sales	338	—	282	5,479	—	—	6,099
Net unrealized losses (gains) on derivatives	2,766	13,694	(577)	—	—	—	15,883
Inventory valuation adjustment	—	—	—	11,033	—	—	11,033
Lower of cost or market adjustments	—	—	504	(105)	—	—	399
(Gain) loss on disposal or impairment of assets, net	(111,393)	6,863	117,516	(30,098)	8	—	(17,104)
Equity-based compensation expense	—	—	—	—	35,241	—	35,241
Acquisition expense	—	—	—	—	263	—	263
Other income, net	535	211	105	604	5,498	—	6,953
Adjusted EBITDA attributable to unconsolidated entities	11,507	579	—	4,308	—	—	16,394
Adjusted EBITDA attributable to noncontrolling interest	—	(737)	—	—	—	—	(737)
Revaluation of liabilities	—	20,607	—	—	—	—	20,607
Other	10,617	461	85	—	—	—	11,163
Discontinued operations	—	—	—	—	—	110,210	110,210
Adjusted EBITDA	$ 117,661	$ 116,070	$ 49,739	$ 49,255	$ (34,685)	$ 110,210	$ 408,250

	Year Ended March 31, 2017						
	Crude Oil Logistics	Water Solutions	Liquids	Refined Products and Renewables	Corporate and Other	Discontinued Operations	Consolidated
	(in thousands)						
Operating (loss) income	$ (17,475)	$ 44,587	$ 43,252	$ 222,546	$ (86,985)	$ —	$ 205,925
Depreciation and amortization	54,144	101,758	19,163	1,562	3,612	—	180,239
Amortization recorded to cost of sales	384	—	781	5,663	—	—	6,828
Net unrealized (gains) losses on derivatives	(1,513)	(2,088)	216	—	—	—	(3,385)
Inventory valuation adjustment	—	—	—	7,368	—	—	7,368
Lower of cost or market adjustments	—	—	—	(1,283)	—	—	(1,283)
Loss (gain) on disposal or impairment of assets, net	10,704	(85,560)	92	(134,125)	(1)	—	(208,890)
Equity-based compensation expense	—	—	—	—	53,102	—	53,102
Acquisition expense	—	—	—	—	1,771	—	1,771
Other (expense) income, net	(412)	739	73	19,263	6,949	—	26,612
Adjusted EBITDA attributable to unconsolidated entities	11,589	106	—	3,975	—	—	15,670
Adjusted EBITDA attributable to noncontrolling interest	—	(9,210)	—	—	—	—	(9,210)
Revaluation of liabilities	—	12,761	—	—	—	—	12,761
Other	1,996	368	79	—	—	—	2,443
Discontinued operations	—	—	—	—	—	91,366	91,366
Adjusted EBITDA	$ 59,417	$ 63,461	$ 63,656	$ 124,969	$ (21,552)	$ 91,366	$ 381,317

Liquidity, Sources of Capital and Capital Resource Activities

Our principal sources of liquidity and capital are the cash flows from our operations, borrowings under the Revolving Credit Facility and accessing capital markets. See Note 8 to our consolidated financial statements included in this Annual Report for a detailed description of our long-term debt. Our cash flows from operations are discussed below.

Our borrowing needs vary during the year due in part to the seasonal nature of our Liquids and Refined Products and Renewables businesses. Our greatest working capital borrowing needs generally occur during the period of June through December, when we are building our natural gas liquids inventories in anticipation of the heating season as well as building our gasoline inventory in anticipation of the winter gasoline contango and blending season. Our working capital borrowing needs generally decline during the period of January through March, when the cash flows from our Liquids segment are the greatest and gasoline inventories need to be minimized due to certain inventory requirements.

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders as of the record date. Available cash for any quarter generally consists of all cash on hand at the end of that quarter, less the amount of cash reserves established by our general partner, to (i) provide for the proper conduct of our business, (ii) comply with applicable law, any of our debt instruments or other agreements, and (iii) provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.

We believe that our anticipated cash flows from operations and the borrowing capacity under the Revolving Credit Facility are sufficient to meet our liquidity needs. If our plans or assumptions change or are inaccurate, or if we make acquisitions, we may need to raise additional capital or sell assets. Our ability to raise additional capital, if necessary, depends on various factors and conditions, including market conditions. We cannot give any assurances that we can raise additional capital to meet these needs (see Part I, Item 1A–"Risk Factors"). Commitments or expenditures, if any, we may make toward any acquisition projects are at our discretion.

We have made the strategic decision to completely exit the Retail Propane business and Bakken and South Pecos water disposal businesses and re-deploy proceeds from these sales to repay certain indebtedness and for certain near-term strategic growth opportunities, primarily in the Water Solutions segment. We believe our Water Solutions and Crude Oil Logistics businesses have organic growth opportunities with the activity in our core basins, including the Delaware Basin and DJ Basin in particular. We plan to pursue a strategy of growth through acquisitions as well as undertaking certain capital expansion projects. We expect to consider financing future acquisitions and capital expansion projects through available capacity on the Revolving Credit Facility or other forms of financing.

Other sources of liquidity during the year ended March 31, 2019 are discussed below.

Dispositions

On May 3, 2018, we sold our previously held 20% interest in E Energy Adams, LLC for net proceeds of $18.6 million, which we used to pay down amounts outstanding under the Revolving Credit Facility.

On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior for total consideration of $889.8 million in cash. On August 14, 2018, we sold our previously held interest in Victory Propane. We used the proceeds to pay down amounts outstanding under the Revolving Credit Facility.

On November 30, 2018, we completed the sale of NGL Water Solutions Bakken, LLC to an affiliate of Tallgrass Energy, LP for $85.0 million in net cash proceeds, which we used to pay down amounts outstanding under the Revolving Credit Facility.

On February 28, 2019, we completed the sale of our South Pecos water disposal business to a subsidiary of WaterBridge Resources LLC for $232.2 million in net cash proceeds, which we used to fund the acquisition of a natural gas liquids terminal business with the remaining proceeds used to partially fund the redemption of our 2019 Notes.

Subsequent Events

See Note 19 to our consolidated financial statements included in this Annual Report for a discussion of transactions that occurred subsequent to March 31, 2019.

Long-Term Debt

Credit Agreement

We are party to a $1.765 billion credit agreement (the “Credit Agreement”) with a syndicate of banks. As of March 31, 2019, the Credit Agreement includes a revolving credit facility to fund working capital needs, which had a capacity of $1.250 billion for cash borrowings and letters of credit (the “Working Capital Facility”), and a revolving credit facility to fund acquisitions and expansion projects, which had a capacity of $515.0 million (the “Expansion Capital Facility,” and together with the Working Capital Facility, the “Revolving Credit Facility”). The Revolving Credit Facility allows us to reallocate amounts between the Expansion Capital Facility and Working Capital Facility. We had letters of credit of $143.4 million on the Working Capital Facility at March 31, 2019. The commitments under the Credit Agreement expire on October 5, 2021.

On February 6, 2019, we amended the Credit Agreement, to, among other things, reset the basket for the repurchase of common units with a limit of $150 million in aggregate during the remaining term of the Credit Agreement, not to exceed $50 million per fiscal quarter, so long as, both immediately before and after giving pro forma effect to the repurchases, the Partnership’s Leverage Ratio (as defined in the Credit Agreement) is less than 3.25x and Revolving Availability (also as defined in the Credit Agreement) is greater than or equal to $200 million. In addition, the amendment decreases the Maximum Total Leverage Indebtedness Ratio beginning September 30, 2019 with a further decrease beginning March 31, 2020, and amends the defined term “Consolidated EBITDA” to exclude the “Gavilon Energy EPA Settlement” (as defined in the Credit Agreement) solely for the two quarters ending December 31, 2018 and March 31, 2019.

We were in compliance with the covenants under the Credit Agreement at March 31, 2019.

Senior Unsecured Notes

The senior unsecured notes include, as defined below, the 2019 Notes, 2021 Notes, 2023 Notes, 2025 Notes and 2026 Notes (collectively, the "Senior Unsecured Notes").

Issuances

On October 24, 2016, we issued $700.0 million of 7.50% Senior Unsecured Notes Due 2023 (the "2023 Notes"). Interest is payable on May 1 and November 1 of each year. The 2023 Notes mature on November 1, 2023.

On February 22, 2017, we issued $500.0 million of 6.125% Senior Unsecured Notes Due 2025 (the "2025 Notes"). Interest is payable on March 1 and September 1 of each year. The 2025 Notes mature on March 1, 2025.

On April 9, 2019, we issued $450.0 million of 7.50% Senior Unsecured Notes Due 2026 (the "2026 Notes") in a private placement. Interest is payable on April 15 and October 15 of each year, beginning on October 15, 2019. We received net proceeds of $441.8 million, after the initial purchasers' discount of $6.8 million and offering costs of $1.5 million. The 2026 Notes mature on April 15, 2026.

Redemptions and Repurchases

On October 16, 2018, we redeemed all of the remaining outstanding 6.875% Senior Unsecured Notes Due 2021 ("2021 Notes"). On March 15, 2019, we redeemed all of the remaining outstanding 5.125% Senior Unsecured Notes Due 2019 ("2019 Notes"). We used amounts available under the Revolving Credit Facility to fund the redemptions as well as proceeds from the sale of our South Pecos water disposal business in February 2019.

During the year ended March 31, 2019, we repurchased $25.4 million of the 2019 Notes and $8.6 million of the 2023 Notes.

Compliance

At March 31, 2019, we were in compliance with the covenants under all of the Senior Unsecured Notes indentures.

For a further discussion of the Revolving Credit Facility and Senior Unsecured Notes redemptions and repurchases, see Note 8 to our consolidated financial statements included in this Annual Report.

Revolving Credit Facility Borrowings

The following table summarizes the Revolving Credit Facility borrowings for the periods indicated:

	Average Balance Outstanding	Lowest Balance	Highest Balance
		(in thousands)	
Year Ended March 31, 2019			
Expansion capital borrowings	$ 82,816	$ —	$ 330,000
Working capital borrowings	$ 852,552	$ 439,000	$ 1,095,500
Year Ended March 31, 2018			
Expansion capital borrowings	$ 167,900	$ —	$ 397,000
Working capital borrowings	$ 837,651	$ 719,500	$ 1,014,500

At-The-Market Program

On August 24, 2016, we entered into an equity distribution agreement in connection with an at-the-market program (the "ATM Program") pursuant to which we may issue and sell up to $200.0 million of common units. We are under no obligation to issue equity under the ATM Program. We did not sell any common units under the ATM Program during the year ended March 31, 2019, and approximately $134.7 million remained available for sale under the ATM Program at March 31, 2019.

Capital Expenditures, Acquisitions and Other Investments

The following table summarizes expansion and maintenance capital expenditures (which excludes additions for tank bottoms and line fill and has been prepared on the accrual basis), acquisitions and other investments for the periods indicated. Amounts in the table below include capital expenditures and acquisitions related to our former Retail Propane segment.

	Capital Expenditures			Other
Year Ended March 31,	**Expansion (1)**	**Maintenance (2)**	**Acquisitions (3)**	**Investments (4)**
		(in thousands)		
2019	$ 418,920	$ 49,177	$ 348,836	$ 389
2018	$ 155,213	$ 37,713	$ 50,417	$ 27,889
2017	$ 334,383	$ 26,073	$ 122,832	$ 44,864

(1) Amount for the year ended March 31, 2018 includes intangible assets received as consideration as part of the Sawtooth joint venture transaction (see Note 16 to our consolidated financial statements included in this Annual Report). Amounts for the years ended March 31, 2019, 2018 and 2017 include $0.4 million, $8.5 million and $5.4 million, respectively, related to our former Retail Propane segment.

(2) Amounts for the years ended March 31, 2019, 2018 and 2017 include $3.8 million, $14.0 million and $13.6 million, respectively, related to our former Retail Propane segment.

(3) Amounts for the years ended March 31, 2019, 2018 and 2017 include$31.9 million, $30.5 million and $80.9 million, respectively, related to our former Retail Propane segment.

(4) Amounts for the years endedMarch 31, 2019 and 2018 primarily related to contributions made to unconsolidated entities. Amount for the year ended March 31, 2017 primarily related to payments made to terminate a development agreement and other liabilities. There were no amounts related to our former Retail Propane segment for the years ended March 31, 2019, 2018 or 2017.

We currently expect to invest approximately $1.2 billion to $1.3 billion on acquisitions and growth capital expenditures during fiscal year 2020, which includes approximately $970 million for the acquisition of Mesquite Disposals Unlimited, LLC and certain other transactions in our Water Solutions segment that have already closed (see Note 19 to our consolidated financial statements included in this Annual Report).

Cash Flows

The following table summarizes the sources (uses) of our cash flows from continuing operations for the periods indicated:

	Year Ended March 31,		
Cash Flows Provided by (Used in):	**2019**	**2018**	**2017**
		(in thousands)	
Operating activities, before changes in operating assets and liabilities	$ 263,513	$ 176,052	$ 159,613
Changes in operating assets and liabilities	44,001	(122,423)	(257,413)
Operating activities-continuing operations	$ 307,514	$ 53,629	$ (97,800)
Investing activities-continuing operations	$ (392,286)	$ 105,343	$ (264,265)
Financing activities-continuing operations	$ (793,920)	$ (390,445)	$ 375,087

Operating Activities-Continuing Operations. The seasonality of our Liquids business has a significant effect on our cash flows from operating activities. Increases in natural gas liquids prices typically reduce our operating cash flows due to higher cash requirements to fund increases in inventories, and decreases in natural gas liquids prices typically increase our operating cash flows due to lower cash requirements to fund increases in inventories. In our Liquids business, we typically experience operating losses or lower operating income during our first and second quarters, or the six months ending September 30, as a result of lower volumes of natural gas liquids sales and when we are building our inventory levels for the upcoming heating season. The heating season runs through the six months ending March 31. The seasonal motor fuel blend during the third quarter of our fiscal year impacts the value of our gasoline inventory in our Refined Products and Renewables business and also represents a period when we build inventory into our system. We borrow under the Revolving Credit Facility to supplement our operating cash flows during the periods in which we are building inventory. Our operations, and as a result our cash flows, are also impacted by positive and negative movements in commodity prices, which cause fluctuations in the value of inventory, accounts receivable and payables, due to increases and decreases in revenues and cost of sales. The increase in net cash provided by operating activities during the year ended March 31, 2019 was due primarily to fluctuations in the value of accounts receivable, inventory and accounts payable during the year ended March 31, 2019. The increase in net cash provided by operating activities during the year ended March 31, 2018 was due primarily to higher inventory as a result of the purchase of additional pipeline capacity allocations in our Refined Products and Renewables segment during the year ended March 31, 2017.

Investing Activities-Continuing Operations. Net cash used in investing activities was $392.3 million during the year ended March 31, 2019, compared to net cash provided by investing activities of $105.3 million during the year ended March 31, 2018. The increase in net cash used in investing activities was due primarily to:

- an increase in capital expenditures from $133.8 million during the year ended March 31, 2018 to $455.6 million during the year ended March 31, 2019 due primarily to capital expenditures for expansion projects in our Water Solutions segment; and
- a $297.0 million increase in cash paid for acquisitions during the year ended March 31, 2019.

These increases in net cash used in investing activities were partially offset by a $118.8 million decrease in payments to settle derivatives.

Net cash provided by investing activities was $105.3 million during the year ended March 31, 2018, compared to net cash used in investing activities of $264.3 million during the year ended March 31, 2017. The increase in net cash provided by investing activities was due primarily to:

- a decrease in capital expenditures from $344.9 million during the year ended March 31, 2017 to $133.8 million during the year ended March 31, 2018 due primarily to capital expenditures for the Grand Mesa Pipeline and the purchase of additional pipeline capacity allocations during the year ended March 31, 2017;
- a $201.0 million increase in proceeds from sales of assets due primarily to the sales of our previously held 50% interest in Glass Mountain and a portion of Sawtooth and an increase in proceeds from the sale of excess pipe in our Crude Oil Logistics segment during the year ended March 31, 2018 and the sales of TLP common units we owned and Grassland during the year ended March 31, 2017; and
- a $16.9 million payment to terminate a development agreement during the year ended March 31, 2017 (see Note 16 to our consolidated financial statements included in this Annual Report).

These increases in net cash provided by investing activities were partially offset by a $63.3 million increase in payments to settle derivatives.

Financing Activities-Continuing Operations. Net cash used in financing activities was $793.9 million during the year ended March 31, 2019, compared to net cash used in financing activities of $390.4 million during the year ended March 31, 2018. The increase in net cash used in financing activities was due primarily to:

- an increase in repurchases and redemptions of our senior unsecured notes of $250.4 million during the year ended March 31, 2019; and
- a decrease of $202.7 million due to proceeds received from the sale of our preferred units during the year ended March 31, 2018.

These increases in net cash used in financing activities were partially offset by an increase of $46.5 million in borrowings on the Revolving Credit Facility (net of repayments) during the year ended March 31, 2019.

Net cash used in financing activities was $390.4 million during the year ended March 31, 2018, compared to net cash provided by financing activities of $375.1 million during the year ended March 31, 2017. The increase in net cash used in financing activities was due primarily to:

- $1.2 billion in proceeds from the issuance of the 2023 Notes and 2025 Notes during the year ended March 31, 2017;
- an increase of $465.5 million for repayments and repurchases of all of our remaining outstanding senior secured notes and a portion of our Senior Unsecured Notes during the year ended March 31, 2018;

- a decrease of $319.4 million in proceeds from the sale of our common units and preferred units during the year ended March 31, 2018;
- an increase of $43.3 million in distributions paid to our general partners and common unitholders, preferred unitholders and noncontrolling interest owners during the year ended March 31, 2018; and
- $26.4 million for the repurchase of a portion of our common units and warrants related to our 10.75% Class A Convertible Preferred Units ("Class A Preferred Units") during the year ended March 31, 2018.

These increases in net cash used in financing activities were partially offset by:

- an increase of $1.2 billion in borrowings on the revolving credit facilities (net of repayments) during the year ended March 31, 2018;
- the repayment of equipment loans totaling $41.7 million during the year ended March 31, 2017;
- $30.8 million in debt issuance costs for the issuance of the 2023 Notes and 2025 Notes and the amendment and restatement of the Credit Agreement during the year ended March 31, 2017; and
- a $25.9 million release of contingent consideration liabilities related to the termination of a development agreement during the year ended March 31, 2017 (see Note 16 to our consolidated financial statements included in this Annual Report).

Distributions Declared

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders as of the record date. See further discussion of our cash distribution policy in Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities included in this Annual Report.

On March 15, 2019, the board of directors of our general partner declared a distribution on the 9.00% Class B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Class B Preferred Units") for the three months ended March 31, 2019 of $4.7 million in the aggregate, which was paid to the holders of the Class B Preferred Units on April 15, 2019.

On April 24, 2019, the board of directors of our general partner declared a distribution of $0.39 per common unit to the unitholders of record on May 7, 2019. In addition, the board of directors of our general partner declared a distribution to the holders of the Class A Preferred Units of $4.0 million in the aggregate. The distributions were paid to the common unitholders on May 15, 2019 and to the holders of the Class A Preferred Units on May 10, 2019.

The initial distribution on our 9.625% Class C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units will accumulate after the original issuance date until June 30, 2019 and will be payable on July 15, 2019, if declared.

For a further discussion of our distributions, see Note 10 to our consolidated financial statements included in this Annual Report.

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Contractual Obligations

The following table summarizes our contractual obligations at March 31, 2019 for our fiscal years ending thereafter:

	Total	Years Ending March 31, 2020	2021	2022	2023	2024	Thereafter
				(in thousands)			
Principal payments on long-term debt:							
Expansion capital borrowings	$ 275,000	$ —	$ —	$ 275,000	$ —	$ —	$ —
Working capital borrowings	896,000	—	—	896,000	—	—	—
Senior unsecured notes	996,458	—	—	—	—	607,323	389,135
Other long-term debt	5,331	648	4,683	—	—	—	—
Interest payments on long-term debt:							
Revolving Credit Facility (1)	146,419	56,315	56,315	33,789	—	—	—
Senior unsecured notes	370,755	69,384	69,384	69,384	69,384	69,384	23,835
Other long-term debt	319	210	109	—	—	—	—
Letters of credit	143,360	—	—	143,360	—	—	—
Future minimum lease payments under noncancelable operating leases	432,295	127,718	105,697	83,595	54,599	18,841	41,845
Future minimum throughput payments under noncancelable agreements (2)	43,203	43,203	—	—	—	—	—
Construction commitments (3)	29,747	29,747	—	—	—	—	—
Fixed-price commodity purchase commitments:							
Crude oil	60,227	60,227	—	—	—	—	—
Natural gas liquids	5,298	5,033	265	—	—	—	—
Index-price commodity purchase commitments (4):							
Crude oil (5)	3,110,615	1,703,112	526,420	411,071	269,990	200,022	—
Natural gas liquids	565,212	564,013	1,199	—	—	—	—
Total contractual obligations	$ 7,080,239	$ 2,659,610	$ 764,072	$ 1,912,199	$ 393,973	$ 895,570	$ 454,815

(1) The estimated interest payments on the Revolving Credit Facility are based on principal and letters of credit outstanding atMarch 31, 2019. See Note 8 to our consolidated financial statements included in this Annual Report for additional information on the Credit Agreement.

(2) We have executed noncancelable agreements with crude oil pipeline operators, which guarantee us minimum monthly shipping capacity on the pipelines. As a result, we are required to pay the minimum shipping fees if actual shipments are less than our allotted capacity. Under certain agreements we have the ability to recover minimum shipping fees previously paid if our shipping volumes exceed the minimum monthly shipping commitment during each month remaining under the agreement, with some contracts containing provisions that allow us to continue shipping up to six months after the maturity date of the contract in order to recapture previously paid minimum shipping delinquency fees. A third party has agreed to assume all rights and privileges and to be fully responsible for any minimum shipping fees due for actual shipments that are less than our allotted capacity related to $30.0 million of the fiscal year 2020 amount under a definitive agreement we signed during the three months ended June 30, 2018. See Note 9 and Note 13 to our consolidated financial statements included in this Annual Report for additional information.

(3) At March 31, 2019, the construction commitments relate to three new towboats and four new barges currently being built.

(4) Index prices are based on a forward price curve atMarch 31, 2019. A theoretical change of $0.10 per gallon of natural gas liquids in the underlying commodity price at March 31, 2019 would result in a change of$102.6 million in the value of our index-price natural gas liquids purchase commitments. A theoretical change of $1.00 per barrel of crude oil in the underlying commodity price at March 31, 2019 would result in a change of $58.4 million in the value of our index-price crude oil purchase commitments. See Note 9 to our consolidated financial statements included in this Annual Report for further detail of the commitments.

(5) Our crude oil index-price purchase commitments exceed our crude oil index-price sales commitments (see Note 9 to our consolidated financial statements included in this Annual Report) due primarily to our long-term purchase commitments for crude oil that we purchase and ship on the Grand Mesa Pipeline. As these purchase commitments are deliver-or-pay contracts, whereby our counterparty is required to pay us for any volumes not delivered, we have not entered into corresponding long-term sales contracts for volumes we may not receive.

Off-Balance Sheet Arrangements

We do not have any off balance sheet arrangements other than the letters of credit discussed in Note 8 to our consolidated financial statements included in this Annual Report and the operating leases discussed in Note 9 to our consolidated financial statements included in this Annual Report. See Note 2 for a discussion of the lease accounting standard we adopted effective April 1, 2019.

Environmental Legislation

See Part I, Item 1–"Business–Government Regulation–Greenhouse Gas Regulation" for a discussion of proposed environmental legislation and regulations that, if enacted, could result in increased compliance and operating costs. However, at this time we cannot predict the structure or outcome of any future legislation or regulations or the eventual cost we could incur in compliance.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that are applicable to us, see Note 2 to our consolidated financial statements included in this Annual Report.

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires the selection and application of appropriate accounting principles to the relevant facts and circumstances of our operations and the use of estimates made by management. We have identified the following accounting policies that are most important to the portrayal of our consolidated financial position and results of operations. The application of these accounting policies, which requires subjective or complex judgments regarding estimates and projected outcomes of future events, and changes in these accounting policies, could have a material effect on our consolidated financial statements.

Revenue Recognition

Effective April 1, 2018, we recognize revenue for services and products under revenue contracts as our obligations to either perform services or deliver or sell products under the contracts are satisfied. A performance obligation is a promise in a contract to transfer a distinct good or service to the customer. A contract's transaction price is allocated to each distinct performance obligation in the contract and is recognized as revenue when, or as, the performance obligation is satisfied. Our revenue contracts in scope under ASC 606 primarily have a single performance obligation. The evaluation of when performance obligations have been satisfied and the transaction price that is allocated to our performance obligations requires significant judgment and assumptions, including our evaluation of the timing of when control of the underlying good or service has transferred to our customers and the relative stand-alone selling price of goods and services provided to customers under contracts with multiple performance obligations. Actual results can vary from those judgments and assumptions. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion of our revenue recognition policies.

Derivative Financial Instruments

We record all derivative financial instrument contracts at fair value in our consolidated balance sheets except for certain physical contracts that qualify for the normal purchase and normal sale election . Under this accounting policy election, we do not record the physical contracts at fair value at each balance sheet date; instead, we record the purchase or sale at the contracted value once the delivery occurs.

We have not designated any financial instruments as hedges for accounting purposes. All changes in the fair value of our physical contracts that do not qualify as normal purchases and normal sales and settlements (whether cash transactions or non-cash mark-to-market adjustments) are reported either within revenue (for sales contracts) or cost of sales (for purchase contracts) in our consolidated statements of operations, regardless of whether the contract is physically or financially settled.

We utilize various commodity derivative financial instrument contracts to attempt to reduce our exposure to price fluctuations. We do not enter into such contracts for trading purposes. Changes in assets and liabilities from commodity derivative financial instruments result primarily from changes in market prices, newly originated transactions, and the timing of settlements and are reported within cost of sales on the consolidated statements of operations, along with related settlements. We attempt to balance our contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. However, net unbalanced positions can exist or are established based on our assessment of anticipated market movements. Inherent in the resulting contractual portfolio are certain business risks, including commodity price risk and credit risk. Commodity price risk is the risk that the market value of crude oil, natural gas liquids, or refined and renewables products will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. Procedures and limits for managing commodity price risks and credit risks are specified in our market risk policy and credit policy, respectively. Open commodity positions and market price changes are monitored daily and are reported to senior management and to marketing operations personnel. Credit risk is monitored daily and exposure is minimized through customer deposits, restrictions on product liftings, letters of credit, and entering into master netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions.

Impairment of Long-Lived Assets

We evaluate the carrying value of our long-lived assets (property, plant and equipment and amortizable intangible assets) for potential impairment when events and circumstances warrant such a review. A long-lived asset group is considered impaired when the anticipated undiscounted future cash flows from the use and eventual disposition of the asset group is less than its carrying value. We compare the carrying value of the long-lived asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset's unamortized cost may not be recoverable due to impairment, we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of a long-lived asset would increase costs and expenses at that time.

We evaluate our equity method investments for impairment when we believe the current fair value may be less than the carrying amount and record an impairment if we believe the decline in value is other than temporary.

Impairment of Goodwill

Goodwill is subject to at least an annual assessment for impairment. We perform our annual assessment of impairment during the fourth quarter of our fiscal year, and more frequently if circumstances warrant. For purposes of goodwill impairment testing, assets are grouped into "reporting units". A reporting unit is either an operating segment or a component of an operating segment, depending on how similar the components of the operating segment are to each other in terms of operational and economic characteristics. For each reporting unit, we perform a qualitative assessment of relevant events and circumstances about the likelihood of goodwill impairment. If it is deemed more likely than not that the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not required. The qualitative assessment is based on reviewing the totality of several factors, including macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other entity specific events (for example, changes in management) or other events such as selling or disposing of a reporting unit. The determination of a reporting unit's fair value is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value. If future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations. We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value. See Note 6 to our consolidated financial statements included in this Annual Report for a further discussion of our goodwill impairment assessment.

Asset Retirement Obligations

We have contractual and regulatory obligations at certain facilities for which we have to perform remediation, dismantlement, or removal activities when the assets are retired. We are required to recognize the fair value of a liability for an asset retirement obligation if a reasonable estimate of fair value can be made. In order to determine the fair value of such a liability, we must make certain estimates and assumptions including, among other things, projected cash flows, the estimated timing of retirement, a credit-adjusted risk-free interest rate, and an assessment of market conditions, which could significantly impact the estimated fair value of the asset retirement obligation. These estimates and assumptions are very subjective and can vary over time. Our consolidated balance sheet at March 31, 2019 includes a liability of $9.7 million related to asset retirement obligations, which is reported within other noncurrent liabilities.

In addition to the obligations described above, we may be obligated to remove facilities or perform other remediation upon retirement of certain other assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminable. We will record an asset retirement obligation for these assets in the periods in which settlement dates are reasonably determinable.

Depreciation and Amortization Methods and Estimated Useful Lives of Property, Plant and Equipment and Intangible Assets

Depreciation and amortization expense is the systematic write-off of the cost of our property, plant and equipment (net of residual or salvage value, if any) and the cost of our amortizable intangible assets to the results of operations for the quarterly and annual periods during which the assets are used. We depreciate our property, plant and equipment and amortize the majority of our intangible assets using the straight-line method, which results in our recording depreciation and amortization expense evenly over the estimated life of the individual asset. The estimate of depreciation and amortization expense requires us to make assumptions regarding the useful economic lives and residual values of our assets. When we acquire and place our property, plant and equipment in service or acquire intangible assets, we develop assumptions about the useful economic lives and residual values of such assets that we believe to be reasonable; however, circumstances may develop that could require us to change these assumptions in future periods, which would change our depreciation and amortization expense prospectively. Examples of such circumstances include changes in laws and regulations that limit the estimated economic life of an asset, changes in technology that render an asset obsolete, changes in expected salvage values or changes in customer attrition rates.

Acquisitions

To determine if a transaction should be accounted for as a business combination or an acquisition of assets, we first calculate the relative fair values of the assets acquired. If substantially all of the relative fair value is concentrated in a single asset or group of similar assets, or if not but the transaction does not include a significant process (does not meet the definition of a business), we record the transaction as an acquisition of assets. For acquisitions of assets, the purchase price is allocated based on the relative fair values. For an acquisition of assets, goodwill is not recorded. All other transactions are recorded as business combinations.

Fair values of assets acquired and liabilities assumed are based upon available information and may involve engaging an independent third party to perform an appraisal. Estimating fair values can be complex and subject to significant business judgment. We must also identify and include in the allocation all acquired tangible and intangible assets that meet certain criteria, including assets that were not previously recorded by the acquired entity. The estimates most commonly involve property, plant and equipment and intangible assets, including those with indefinite lives. The estimates also include the fair value of contracts including commodity purchase and sale agreements, storage contracts, and transportation contracts. For a business combination, the excess of the purchase price over the net fair value of acquired assets and assumed liabilities is recorded as goodwill, which is not amortized but instead is evaluated for impairment at least annually. Pursuant to GAAP, an entity is allowed a reasonable period of time (not to exceed one year) to obtain the information necessary to identify and measure the fair value of the assets acquired and liabilities assumed in a business combination.

Inventories

Our inventories consist of crude oil, natural gas liquids, gasoline, diesel, ethanol, and biodiesel. Our inventories are valued at the lower of cost or net realizable value, with cost determined using either the weighted-average cost or the first in, first out (FIFO) methods, including the cost of transportation and storage, and with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. In performing this analysis, we consider fixed-price forward commitments. At the end of each fiscal year, we also perform a “lower of cost or net realizable value” analysis; if the cost basis of the inventories would not be recoverable based on the net realizable value at the end of the year, we reduce the book value of the inventories to the recoverable amount. When performing this analysis during interim periods within a fiscal year, accounting standards do not require us to record a lower of cost or net realizable value write-down if we expect the net realizable value to recover by our fiscal year end. The net realizable values of these commodities change on a daily basis as supply and demand conditions change. We are unable to control changes in the net realizable value of these commodities and are unable to determine whether write-downs will be required in future periods. In addition, write-downs at interim periods could be required if we cannot conclude that net realizable values will recover sufficiently by our fiscal year end.

Equity-Based Compensation

Our general partner has granted certain restricted units to employees and directors under a long-term incentive plan. The restricted units include awards that vest contingent on the continued service of the recipients through the vesting date (the “Service Awards”). The awards may also vest upon a change of control, at the discretion of the board of directors of our general partner.

Service Awards are valued at the average of the high/low sales price as of the grant date less the present value of the expected distribution stream over the vesting period using a risk-free interest rate. We record the expense for each Service Award on a straight-line basis over the requisite period for the entire award (that is, over the requisite service period of the last separately vesting portion of the award), ensuring that the amount of compensation cost recognized at any date at least equals the portion of the grant-date value of the award that is vested at that date.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

A significant portion of our long-term debt is variable-rate debt. Changes in interest rates impact the interest payments of our variable-rate debt but generally do not impact the fair value of the liability. Conversely, changes in interest rates impact the fair value of our fixed-rate debt but do not impact its cash flows.

The Revolving Credit Facility is variable-rate debt with interest rates that are generally indexed to bank prime or LIBOR interest rates. At March 31, 2019, we had $1.2 billion of outstanding borrowings under the Revolving Credit Facility at a weighted average interest rate of 4.39%. A change in interest rates of 0.125% would result in an increase or decrease of our annual interest expense of $1.5 million, based on borrowings outstanding at March 31, 2019.

Commodity Price and Credit Risk

Our operations are subject to certain business risks, including commodity price risk and credit risk. Commodity price risk is the risk that the market value of crude oil, natural gas liquids, or refined and renewables products will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract.

Procedures and limits for managing commodity price risks and credit risks are specified in our market risk policy and credit policy, respectively. Open commodity positions and market price changes are monitored daily and are reported to senior management and to marketing operations personnel. Credit risk is monitored daily and exposure is minimized through customer deposits, restrictions on product liftings, letters of credit, and entering into master netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions. At March 31, 2019, our primary counterparties were retailers, resellers, energy marketers, producers, refiners, and dealers.

The crude oil, natural gas liquids, and refined and renewables products industries are “margin-based” and “cost-plus” businesses in which gross profits depend on the differential of sales prices over supply costs. We have no control over market conditions. As a result, our profitability may be impacted by sudden and significant changes in the price of crude oil, natural gas liquids, and refined and renewables products.

We engage in various types of forward contracts and financial derivative transactions to reduce the effect of price volatility on our product costs, to protect the value of our inventory positions, and to help ensure the availability of product during periods of short supply. We attempt to balance our contractual portfolio by purchasing volumes when we have a matching purchase commitment from our wholesale and retail customers. We may experience net unbalanced positions from time to time. In addition to our ongoing policy to maintain a balanced position, for accounting purposes we are required, on an ongoing basis, to track and report the market value of our derivative portfolio.

Although we use financial derivative instruments to reduce the market price risk associated with forecasted transactions, we do not account for financial derivative transactions as hedges. All changes in the fair value of our physical contracts that do not qualify as normal purchases and normal sales and settlements (whether cash transactions or non-cash mark-to-market adjustments) are reported either within revenue (for sales contracts) or cost of sales (for purchase contracts) in our consolidated statements of operations, regardless of whether the contract is physically or financially settled.

The following table summarizes the hypothetical impact on the March 31, 2019 fair value of our commodity derivatives of an increase of 10% in the value of the underlying commodity (in thousands):

	Increase (Decrease) To Fair Value
Crude oil (Crude Oil Logistics segment)	$ (10,311)
Propane (Liquids segment)	$ 773
Other products (Liquids segment)	$ (4,175)
Gasoline (Refined Products and Renewables segment)	$ (5,715)
Diesel (Refined Products and Renewables segment)	$ (14,787)
Ethanol (Refined Products and Renewables segment)	$ (4,730)
Biodiesel (Refined Products and Renewables segment)	$ 265
Canadian dollars (Liquids segment)	$ 461

Fair Value

We use observable market values for determining the fair value of our derivative instruments. In cases where actively quoted prices are not available, other external sources are used which incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements beginning on page F-1 of this Annual Report, together with the reports of Grant Thornton LLP, our independent registered public accounting firm, are incorporated by reference into this Item 8.

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, as defined in Rule 13(a)-15(e) and 15(d)-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that are designed to provide reasonable assurance that information required to be disclosed in our filings and submissions under the Exchange Act is recorded, processed, summarized and reported within the periods specified in the rules and forms of the Securities and Exchange Commission ("SEC") and that such information is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure.

We completed an evaluation under the supervision and with participation of our management, including 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 at March 31, 2019. Based on this evaluation, the principal executive officer and principal financial officer of our general partner have concluded that as of March 31, 2019, such disclosure controls and procedures were effective to provide the reasonable assurance described above.

Management's Report on Internal Control Over Financial Reporting

The management of our Delaware limited partnership (the "Partnership") and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13(a)-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, or the COSO framework.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of March 31, 2019.

Our internal control over financial reporting as of March 31, 2019 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report, which appears in Part IV, Item 15–"Exhibits, Financial Statement Schedules" in this Annual Report.

Changes in Internal Control Over Financial Reporting

Other than changes that have resulted or may result from our business combinations during the year ended March 31, 2019, as discussed below, there have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) of the Exchange Act) during the three months ended March 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

We closed several business combinations during the year ended March 31, 2019, as described in Note 4 to our consolidated financial statements included in this Annual Report. At this time, we continue to evaluate the business and internal controls and processes of these acquired businesses and are making various changes to their operating and organizational structure based on our business plan. We are in the process of implementing our internal control structure over these acquired businesses. We expect that our evaluation and integration efforts related to those combined operations will continue into future fiscal quarters.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Board of Directors of our General Partner

NGL Energy Holdings LLC, our general partner, manages our operations and activities on our behalf through its directors and executive officers. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. The NGL Energy GP Investor Group appoints all members to the board of directors of our general partner.

The board of directors of our general partner currently has eight members. The board of directors of our general partner has determined that Mr. James C. Kneale, Mr. Stephen L. Cropper, and Mr. James M. Collingsworth satisfy the New York Stock Exchange ("NYSE") and SEC independence requirements. The NYSE does not require a listed publicly traded limited partnership like us to have a majority of independent directors on the board of directors of our general partner. In addition, we are not required to have a nominating and corporate governance committee.

In evaluating director candidates, the NGL Energy GP Investor Group assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the board of directors of our general partner to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties. Our general partner has no minimum qualifications for director candidates. In general, however, the NGL Energy GP Investor Group reviews and evaluates both incumbent and potential new directors in an effort to achieve diversity of skills and experience among the directors of our general partner and in light of the following criteria:

- experience in business, government, education, technology or public interests;
- high-level managerial experience in large organizations;
- breadth of knowledge regarding our business and industry;
- specific skills, experience or expertise related to an area of importance to us, such as energy production, consumption, distribution or transportation, government, policy, finance or law;
- moral character and integrity;
- commitment to our unitholders' interests;
- ability to provide insights and practical wisdom based on experience and expertise;
- ability to read and understand financial statements; and
- ability to devote the time necessary to carry out the duties of a director, including attendance at meetings and consultation on partnership matters.

Although our general partner does not have a formal policy in regard to the consideration of diversity in identifying director nominees, qualified candidates for nomination to the board are considered without regard to race, color, religion, gender, ancestry or national origin.

Directors and Named Executive Officers

Directors of our general partner are appointed by the NGL Energy GP Investor Group and hold office until their successors have been duly elected and qualified or until the earlier of their death, resignation, removal or disqualification. Named executive officers are appointed by, and serve at the discretion of, the board of directors of our general partner. The following table summarizes information regarding the directors of our general partner and our named executive officers as of May 28, 2019.

Name	Age	Position with NGL Energy Holdings LLC
H. Michael Krimbill	65	Chief Executive Officer and Director
Robert W. Karlovich III	42	Executive Vice President and Chief Financial Officer
Kurston P. McMurray	47	Executive Vice President and General Counsel and Secretary
Lawrence J. Thuillier	48	Chief Accounting Officer
Shawn W. Coady	57	Director
James M. Collingsworth	64	Director
Stephen L. Cropper	69	Director
Bryan K. Guderian	59	Director
James C. Kneale	67	Director
John T. Raymond	48	Director
L. John Schaufele IV	36	Director

H. Michael Krimbill. Mr. Krimbill has served as our Chief Executive Officer since October 2010 and as a member of the board of directors of our general partner since its formation in September 2010. From February 2007 through September 2010, Mr. Krimbill managed private investments. Mr. Krimbill was the President and Chief Financial Officer of Energy Transfer Partners, L.P. from 2004 until his resignation in January 2007. Mr. Krimbill joined Heritage Propane Partners, L.P., the predecessor of Energy Transfer Partners, L.P., as Vice President and Chief Financial Officer in 1990. Mr. Krimbill was President of Heritage Propane Partners, L.P. from 1999 to 2000 and President and Chief Executive Officer of Heritage Propane Partners, L.P. from 2000 to 2005. Mr. Krimbill also served as a director of Energy Transfer Equity, the general partner of Energy Transfer Partners, L.P., from 2000 to January 2007, Williams Partners L.P. from 2007 to September 2012, and Pacific Commerce Bank from January 2011 to March 2015.

Mr. Krimbill brings leadership, oversight and financial experience to the board. Mr. Krimbill provides expertise in managing and operating a publicly traded partnership, including substantial expertise in successfully acquiring and integrating propane and midstream businesses. Mr. Krimbill also brings financial expertise to the board, including his prior service as a chief financial officer. Mr. Krimbill's experience serving on other public company boards is also a valuable asset to our board of directors.

Robert W. Karlovich III. Mr. Karlovich has served as our Executive Vice President and Chief Financial Officer since February 2016. Prior to joining NGL, Mr. Karlovich served as Chief Financial Officer of Targa Pipeline Partners, a subsidiary of Targa Resources Partners, LP, from February 2015 through February 2016, and as Senior Vice President of Commercial and Business Development for Targa Resources Partners, LP from November 2015 to February 2016. Mr. Karlovich served in various roles at Atlas Pipeline Partners, L.P. and its subsidiaries ("APL"), including most recently as Chief Financial Officer, from September 2006 to February 2015 when APL merged with Targa Resources Partners, LP. Mr. Karlovich served in various roles at Syntroleum Corporation from February 2004 to September 2006. Prior to that, Mr. Karlovich worked at Arthur Andersen LLP and Grant Thornton LLP. Mr. Karlovich is a certified public accountant.

Kurston P. McMurray. Mr. McMurray has served as our Executive Vice President and General Counsel and Secretary since October 2016. Mr. McMurray joined NGL in February 2015 as Vice President, Legal and Corporate Secretary. Prior to joining NGL, Mr. McMurray practiced law in the Tulsa, Oklahoma area since 1998 and was a founding shareholder of Wilkin/McMurray PLLC. Mr. McMurray's private practice specialized in business transactions, real estate, healthcare, banking, corporate governance, corporate management and commercial litigation.

Lawrence J. Thuillier. Mr. Thuillier has served as our Chief Accounting Officer since January 2016. Prior to joining NGL, Mr. Thuillier served in various roles at Eagle Rock Energy Partners, L.P. from December 2007 through October 2015, most recently as Vice President of Financial Reporting and Corporate Controller. Mr. Thuillier served as Assistant Corporate Controller for Exterran Holdings, Inc. (formerly Universal Compression) from November 2006 through November 2007. Prior to that, Mr. Thuillier served in various roles at Deloitte & Touche LLP, most recently as Audit Senior Manager.

Shawn W. Coady. Dr. Coady had served as our President and Chief Operating Officer, Retail Division, since April 2012 and previously served as our Co-President and Chief Operating Officer, Retail Division from October 2010 through April 2012. On March 30, 2018, Dr. Coady, as a result of the sale of a portion of our Retail Propane segment (see Note 17 to our consolidated financial statements included in this Annual Report for a further discussion), resigned from his position as President and Chief Operating Officer, Retail Division, but will remain as a member of the board of directors of our general partner. Dr. Coady served as a member of the board of directors of our general partner since its formation in September 2010. Dr. Coady served as an officer of Hicks Oils & Hicksgas, Incorporated ("HOH"), from March 1989 to September 2010 when HOH contributed its propane and propane related assets to Hicksgas LLC, and the membership interests in Hicksgas LLC were contributed to us as part of our formation transactions. Dr. Coady was also the President of Hicksgas Gifford, Inc. from March 1989 until the membership interests in the company were contributed to us as part of our formation transactions. Dr. Coady has served as a director for the National Propane Gas Association from 2004 to 2015 and as a member of the executive committee of the Illinois Propane Gas Association from 2004 to March 2015.

Dr. Coady brings valuable operational experience to the board. Dr. Coady has over 25 years of experience in the retail propane industry, and provides expertise in both acquisition and organic growth strategies. Dr. Coady also provides insight into developments and trends in the propane industry through his leadership roles in industry associations.

James M. Collingsworth. Mr. Collingsworth has served on the board of directors of our general partner since January 2015. Mr. Collingsworth previously served as a Senior Vice President of the general partner of Enterprise Products Partners L.P. from November 2001 through January 2014. Prior to that, Mr. Collingsworth served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001. Prior to joining Texaco, Mr. Collingsworth was director of feedstocks for Rexene Petrochemical Company from 1988 to 1991 and served in the MAPCO, Inc. organization from 1973 to 1988 in various capacities, including customer service and business development manager of the Mid-America and Seminole pipelines. Mr. Collingsworth currently serves on the board of directors of Martin Midstream Partners L.P. and American Ethane Co.

Mr. Collingsworth brings a wealth of in-depth industry experience to the board. Mr. Collingsworth has worked in all facets of the midstream and petrochemical industry for more than 40 years.

Stephen L. Cropper. Mr. Cropper joined the board of directors of our general partner in June 2011. Mr. Cropper held various positions during his 25-year career at The Williams Companies, Inc., including serving as the President and Chief Executive Officer of Williams Energy Services, a Williams operating unit involved in various energy-related businesses, until his retirement in 1998. Mr. Cropper served as a director of Energy Transfer Partners, L.P. from 2000 through 2005. Since Mr. Cropper's retirement from The Williams Companies, Inc. in 1998, he has been a consultant and private investor and also served as a director of Sunoco Logistics Partners, L.P., NRG Energy, Inc., Berry Petroleum Company, and Rental Car Finance Corp., a subsidiary of Dollar Thrifty Automotive Group. Mr. Cropper currently serves on the board of directors of QuikTrip Corporation and Wawa Inc.

Mr. Cropper brings substantial experience in the energy business and in the marketing of energy products to the board. With his significant management and governance experience, Mr. Cropper provides important skills in identifying, assessing and addressing various business issues. As a director for other public companies, Mr. Cropper also provides cross board experience.

Bryan K. Guderian. Mr. Guderian joined the board of directors of our general partner in May 2012. Mr. Guderian has served as Executive Vice President of Business Development of WPX Energy, Inc. ("WPX") since February 2018. Mr. Guderian served as Senior Vice President of Business Development of WPX from October 2014 to February 2018 and as Senior Vice President of Operations of WPX from August 2011 to October 2014. Mr. Guderian previously served as Vice President of the Exploration & Production unit of The Williams Companies, Inc. from 1998 until August 2011, where he had responsibility for overseeing international operations. Mr. Guderian served as a director of Apco Oil & Gas International Inc., from 2002 to 2015 and as a director of Petrolera Entre Lomas S.A. from 2003 to 2015.

Mr. Guderian brings considerable upstream experience to the board including executive, operational and financial expertise from 30 years of petroleum industry involvement, the majority of which has been focused in exploration and production.

James C. Kneale. Mr. Kneale joined the board of directors of our general partner in May 2011. Mr. Kneale served as President and Chief Operating Officer of ONEOK, Inc., from January 2007, and ONEOK Partners, L.P., from May 2008, until his retirement in January 2010. After joining ONEOK in 1981, Mr. Kneale served in various other roles, including Chief Financial Officer from 1999 through 2006. Mr. Kneale also served as a director of ONEOK Partners, L.P. from 2006 until his retirement in January 2010.

Mr. Kneale brings extensive executive, financial and operational experience to the board. With nearly 30 years of experience in the natural gas liquids industry in numerous positions, Mr. Kneale provides valuable insight into our business and industry.

John T. Raymond. Mr. Raymond joined the board of directors of our general partner in August 2013. Mr. Raymond is the Founder and Majority Owner of The Energy & Minerals Group ("EMG") of which he has been a Managing Partner and the Chief Executive Officer since its September 2006 inception. Mr. Raymond has held executive leadership positions with various energy companies, including President and Chief Executive Officer of Plains Resources Inc. (the predecessor entity of Vulcan Energy Corporation), President and Chief Operating Officer of Plains Exploration and Production Company and was a Director of Plains All American Pipeline, LP.

Mr. Raymond also currently serves as a director of American Energy Ohio Holdings, LLC, Ferus Inc., Ferus Natural Gas Fuels Inc., Iron Ore Holdings, Lighthouse Oil & Gas GP, LLC, MarkWest Utica EMG, LLC, Medallion Midstream, LLC, Plains All American GP LLC, PAA GP Holdings LLC, Tallgrass MLP GP LLC and Tallgrass Management, LLC. Mr. Raymond manages various private investments through personally held Lynx Holdings, LLC.

Mr. Raymond brings extensive financial and industry experience to the board. As a director for other public companies, Mr. Raymond also provides cross board experience.

L. John Schaufele IV. Mr. Schaufele joined the board of directors of our general partner in February 2018. Mr. Schaufele has worked at EMG since 2011. Mr. Schaufele previously worked at a middle-market private equity investment firm and JPMorgan. Mr. Schaufele currently serves as a director of Ascent Resources, LLC, Flat River Minerals Heritage NonOp Holdings, LLC, Heritage Minerals Holdings, LLC, Silver Creek Midstream and White Star Petroleum Holdings, LLC; he was also previously a director of Lighthouse Oil & Gas, Traverse Midstream and Utica Minerals Development, LLC. Mr. Schaufele received a B.S. in Business and Accounting from Washington & Lee University.

Mr. Schaufele brings extensive financial and industry experience to the board. With 15 years of experience in the energy sector, Mr. Schaufele provides valuable insight into our business.

Director Appointment Rights

The Limited Liability Company Agreement of NGL Energy Holdings LLC grants certain parties the right to designate a specified number of persons to serve on the board of directors of our general partner. EMG NGL HC LLC has the right to designate two persons to serve on the board of directors of our general partner, and has designated John T. Raymond and L. John Schaufele IV. The Coady Group (which consists of certain entities controlled by Shawn W. Coady and his brother Todd M. Coady) and the investors who formed the Partnership ("IEP Parties") (which consists of certain entities controlled by H. Michael Krimbill, and two other investors) each have the right to designate one person to serve on the board of directors of our general partner. The Coady Group has designated Shawn W. Coady and the IEP Parties have designated H. Michael Krimbill.

Board Leadership Structure and Role in Risk Oversight

The board of directors of our general partner believes that whether the offices of chairman of the board and chief executive officer are combined or separated should be decided by the board, from time to time, in its business judgment after considering relevant circumstances. The board of directors of our general partner currently does not have a chairman.

The board of directors and its committees regularly review material operational, financial, compensation and compliance risks with senior management. In particular, the audit committee is responsible for risk oversight with respect to financial and compliance risks and risks relating to our audit and independent registered public accounting firm. Our compensation committee considers risk in connection with its design and evaluation of compensation programs for our senior management. Each committee regularly reports to the board of directors.

Audit Committee

The board of directors of our general partner has established an audit committee. The audit committee assists the board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to, among other things:

- retain and terminate our independent registered public accounting firm;
- approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm; and
- establish policies and procedures for the pre-approval of all non-audit services and tax services to be rendered by our independent registered public accounting firm.

The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary.

Mr. Collingsworth, Mr. Cropper, and Mr. Kneale currently serve on the audit committee, and Mr. Kneale serves as the chairman. The board of directors of our general partner has determined that Mr. Kneale is an “audit committee financial expert” as defined under SEC rules and that each member of the audit committee is financially literate. In compliance with the requirements of the NYSE, all of the members of the audit committee are independent directors, as defined in the applicable NYSE and Exchange Act rules.

Compensation Committee

The board of directors of our general partner has established a compensation committee. The compensation committee’s responsibilities include the following, among others:

- establishing the general partner’s compensation philosophy and objectives;
- approving the compensation of the Chief Executive Officer;
- making recommendations to the board of directors with respect to the compensation of other officers and directors; and
- reviewing and making recommendations to the board of directors with respect to incentive compensation and equity-based plans.

Mr. Cropper, Mr. Guderian, and Mr. Kneale currently serve on the compensation committee. Mr. Cropper serves as the chairman. The board of directors has determined that Mr. Cropper and Mr. Kneale are independent directors under applicable NYSE and Exchange Act rules. The NYSE does not require a listed publicly traded limited partnership to have a compensation committee consisting entirely of independent directors.

Delinquent Section 16(a) Reports

Section 16(a) of the Exchange Act requires our general partner’s board of directors and named executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of beneficial ownership and reports of changes in beneficial ownership of our common units and other equity securities with the SEC. Directors, named executive officers and greater than 10% unitholders are required by SEC regulations to furnish to us copies of all Section 16(a) forms they file with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations by our directors and named executive officers, we believe that all reporting obligations of our general partner’s directors and named executive officers and our greater than 10% unitholders under Section 16(a) were satisfied during the year ended March 31, 2019, except for the forfeiture of units upon termination of Mr. Osterman’s employment related to the sale of virtually all of our remaining Retail Propane segment on July 10, 2018, which was delayed due to an administrative error and the acquisition of 95,333 common units by Highstar Capital IV, L.P. upon exercise of warrants on May 11, 2018 was reported late on a Form 4 filed on June 27, 2018.

Corporate Governance

The board of directors of our general partner has adopted a Code of Ethics for the Chief Executive Officer and Senior Financial Officers, or Code of Ethics, that applies to the chief executive officer, chief financial officer, chief accounting officer, controller and all other senior financial and accounting officers of our general partner. Amendments to or waivers from the Code of Ethics will be disclosed on our website. The board of directors of our general partner has also adopted Corporate Governance Guidelines that outline important policies and practices regarding our governance and a Code of Business Conduct and Ethics that applies to the directors, officers and employees of our general partner and the Partnership.

We make available free of charge, within the "Governance" section of our website at http://www.nglenergypartners.com/governance, and in print to any unitholder who so requests, the Code of Ethics, the Corporate Governance Guidelines, the Code of Business Conduct and Ethics and the charters of the audit committee and the compensation committee of the board of directors of our general partner. Requests for print copies may be directed to Investor Relations at investorinfo@nglep.com or to Investor Relations, NGL Energy Partners LP, 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136 or made by telephone at (918) 481-1119. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of the audit committee and/or the board of directors of our general partner, our independent directors meet in an executive session without participation by management or non-independent directors. Mr. Kneale presides over these executive sessions.

Unitholders or interested parties may communicate directly with the board of directors of our general partner, any committee of the board, any independent directors, or any one director, by sending written correspondence by mail addressed to the board, committee or director to the attention of our Secretary at the following address: Name of the Director(s), c/o Secretary, NGL Energy Partners LP, 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136. Communications are distributed to the board, committee, or director as appropriate, depending on the facts and circumstances outlined in the communication.

Item 11. Executive Compensation

Compensation Discussion and Analysis

The year "2019" in the Compensation Discussion and Analysis and the summary compensation table refers to our fiscal year ended March 31, 2019.

Introduction

The board of directors of our general partner has responsibility and authority for compensation-related decisions for our executive officers. The board of directors has formed a compensation committee to develop our compensation program, to determine the compensation of our Chief Executive Officer, and to make recommendations to the board of directors regarding the compensation of our other executive officers. Our executive officers are also officers of our operating companies and are compensated directly by our operating companies. While we reimburse our general partner and its affiliates for all expenses they incur on our behalf, our executive officers do not receive any additional compensation for the services they provide to our general partner.

Our "named executive officers" for fiscal year 2019 were:

- H. Michael Krimbill–Chief Executive Officer
- Robert W. Karlovich III–Executive Vice President and Chief Financial Officer
- Lawrence J. Thuillier–Chief Accounting Officer
- Kurston P. McMurray–Executive Vice President and General Counsel and Secretary
- Vincent J. Osterman–Former President, Retail Propane Operations. Mr. Osterman resigned from employment in conjunction with the sale of virtually all of our remaining Retail Propane segment on July 10, 2018.

Compensation Philosophy

Our compensation philosophy emphasizes pay-for-performance, focused primarily on the ability to increase sustainable quarterly distributions to our unitholders. Pay-for-performance is based on a combination of our performance and the individual executive officer's contribution to our performance. We believe this pay-for-performance approach generally aligns the interests of our executive officers with the interests of our unitholders, and at the same time enables us to maintain a lower level of cash compensation expense in the event our operating and financial performance do not meet our expectations.

Our executive compensation program is designed to provide a total compensation package that allows us to:

- **Attract and retain** individuals with the background and skills necessary to successfully execute our business strategies;
- **Motivate** those individuals to reach short-term and long-term goals in a way that aligns their interests with the interests of our unitholders; and
- **Reward** success in reaching those goals.

Recent Achievements

Our compensation structure is designed to reward our officers for achieving above-market returns for our unitholders. Our achievements during the year ended March 31, 2019 included the following:

- On July 10, 2018, we sold virtually all of our remaining Retail Propane segment for net proceeds of $889.8 million;
- On February 28, 2019, we sold our South Pecos water disposal business for net proceeds of $232.2 million;
- On November 30, 2018, we sold our Bakken saltwater disposal business for net proceeds of $85.0 million; and
- On May 3, 2018, we sold our previously held interest in E Energy Adams, LLC for net proceeds of $18.6 million.

Compensation Highlights

- We paid cash bonuses to Mr. Krimbill, Mr. Karlovich and Mr. McMurray during fiscal year 2019, primarily due to their work related to the sale of virtually all of our remaining Retail Propane segment and our South Pecos and Bakken water disposal businesses.
- The salaries of most of our named executive officers remain below the median of our benchmark peer group. This enables us to grant more performance-based compensation to maintain competitive total compensation packages and achieve a greater degree of alignment of pay and performance.

Factors Enhancing Alignment with Unitholder Interests

- Majority of named executive officer pay is at risk incentive compensation based on annual financial performance and growth in unitholder value;
- Equity-based incentives are the largest single component of officer compensation;
- No excise tax gross-ups; and
- Compensation committee engages an independent compensation adviser.

Compensation Setting Process

Our compensation program for our named executive officers supports our philosophy of pay-for-performance.

- **Role of Management:** Our Chief Executive Officer also provides periodic recommendations to the compensation committee and the board of directors regarding the compensation of our other named executive officers other than his own.
- **Role of the Compensation Committee's Consultant:** In carrying out its responsibilities for establishing, implementing and monitoring the effectiveness of our executive compensation philosophy, plans and programs, our compensation committee has the authority to engage outside experts to assist in its deliberations. During fiscal

year 2019, the compensation committee received compensation advice and data from Pearl Meyer & Partners ("PM&P"). PM&P conducted a competitive review of the principal components of compensation for our executive officers, including our named executive officers. PM&P also provided input on peer group selection (compensation and performance peers), and short and long-term incentive plan design. The compensation committee reviewed the services provided by PM&P and determined that they are independent in providing executive compensation consulting services. In making this determination, the compensation committee noted that during fiscal year 2019:

- PM&P did not provide any services to the Partnership or management other than compensation consulting services requested by or with the approval of the compensation committee;
- PM&P does not provide, directly or indirectly through affiliates, any non-compensation services such as pension consulting or human resource outsourcing;
- PM&P maintains a conflicts policy, which was provided to the compensation committee with specific policies and procedures designed to ensure independence;
- Fees paid to PM&P by the Partnership during fiscal year 2019 were less than 1% of PM&P's total revenue;
- None of the PM&P consultants working on Partnership matters had any business or personal relationship with compensation committee members;
- None of the PM&P consultants working on Partnership matters (or any consultants at PM&P) had any business or personal relationship with any executive officer of the Partnership; and
- None of the PM&P consultants working on Partnership matters own Partnership interests.

The compensation committee continues to monitor the independence of its compensation consultant on a periodic basis. The compensation committee considered the recommendations provided by PM&P in the process of designing the fiscal year 2019 compensation program.

Elements of Executive Compensation

As part of our pay-for-performance approach to executive compensation, the compensation of our executive officers includes a significant component of incentive compensation based on our performance. The following table summarizes the primary elements of compensation in our executive compensation program:

			Objective Supported		
Element	**Primary Purpose**	**How Amount Determined**	**Attract & Retain**	**Motivate & Pay for Performance**	**Unitholder Alignment**
Base Salary	ž Fixed income to compensate executive officers for their level of responsibility, expertise and experience	ž Based on competition in the marketplace for executive talent and abilities	X		
Discretionary Cash Bonus Awards	ž Rewards achievement of specific annual financial and operational performance goals ž Recognizes individual contributions to our performance	ž Based on the named executive officer's relative contribution to achieving or exceeding annual goals	X	X	X
Long-Term Equity Incentive Awards	ž Motivates and rewards the achievement of long-term performance goals, including increasing the market price of our common units and the quarterly distributions to our unitholders ž Provides a forfeitable long-term incentive to encourage executive retention	ž Based on the named executive officer's expected contribution to long-term performance goals	X	X	X

Base Salary

The compensation committee periodically reviews the base salaries of our named executive officers and may recommend adjustments as necessary. We do not make automatic annual adjustments to base salary.

- Mr. Krimbill’s initial base salary of $120,000 was originally determined as part of the negotiations for our formation transactions. In setting the base salaries, the parties considered various factors, including the compensation needed to attract or retain the officers, the historical compensation of the officers, and each officer’s expected individual contribution to our performance. At the request of Mr. Krimbill, the parties agreed that he should receive a lower base salary than our other executive officers at the time because, as our Chief Executive Officer, a significant portion of his compensation should be performance-based, to further align his interests with the interests of our unitholders. In February 2012, the base salary of Mr. Krimbill was reduced to $60,000, based on our operating and financial performance as a result of an unusually warm winter. The base salary of Mr. Krimbill was restored to $120,000 effective November 12, 2012. Effective July 1, 2014, the board of directors increased Mr. Krimbill’s salary to $350,000, in consideration of the fact that his salary was low relative to the benchmark peer group (and remains below the 25th percentile of the peer group). Effective April 1, 2018, Mr. Krimbill’s base salary was increased to $625,000, in consideration of the fact that his salary was low relative to the benchmark peer group.
- Mr. Karlovich’s base salary of $400,000 was negotiated prior to his joining our management team in February 2016. Mr. Karlovich’s base salary was increased to $430,000 in April 2017. On June 10, 2018, Mr. Karlovich’s salary was increased to $500,000, in consideration of the fact that his salary was low relative to the benchmark peer group.
- Mr. Thuillier’s base salary of $250,000 was negotiated prior to his joining our management team in January 2016. In April 2017, Mr. Thuillier’s base salary was increased to $260,000. In April 2018, Mr. Thuillier’s base salary was increased to $268,000. Effective March 31, 2019, Mr. Thuillier’s base salary was increased to $270,000.
- Mr. McMurray’s base salary of $250,000 was negotiated prior to his joining our management team in February 2015. Mr. McMurray’s base salary was increased to $300,000 in April 2017. Effective April 1, 2018, Mr. McMurray’s base salary was increased to $350,000. Effective March 31, 2019, Mr. McMurray’s base salary was increased to $375,000.
- Mr. Osterman’s initial base salary of $125,000 was negotiated at the time he joined our management team upon completion of our acquisition of Osterman Propane. Mr. Osterman’s salary was increased to $200,000 in January 2013, to $250,000 in July 2013 and increased to $315,000 effective April 2, 2017, in consideration of the fact that his salary was low relative to the benchmark peer group. Mr. Osterman resigned from employment in conjunction with the sale of virtually all of our remaining Retail Propane segment on July 10, 2018.

Discretionary Cash Bonus Awards

None of the named executive officers is subject to a formal cash bonus plan, and any cash bonuses are at the discretion of either the board of directors (in the case of Mr. Krimbill) or the compensation committee of the board of directors (in the case of the other named executive officers). Cash bonuses of $1.0 million, $0.7 million and $0.7 million were paid to Mr. Krimbill, Mr. Karlovich and Mr. McMurray, respectively, during fiscal year 2019, primarily due to their work related to the sale of virtually all of our remaining Retail Propane segment and our South Pecos and Bakken water disposal businesses.

Long-Term Equity Incentive Awards

Certain restricted units granted to the named executive officers vest in tranches, contingent only on the continued service of the recipient through the vesting date (the "Service Awards"). The following table summarizes Service Award units granted, vested and/or forfeited during fiscal year 2019 with respect to the named executive officers:

Name	Unvested Units at March 31, 2018	Units Granted	Units Vested	Units Forfeited	Unvested Units at March 31, 2019
H. Michael Krimbill (1)	200,000	300,000	(100,000)	—	400,000
Robert W. Karlovich III (2)	62,500	25,000	(25,000)	—	62,500
Lawrence J. Thuillier (3)	25,000	21,551	(21,551)	—	25,000
Kurston P. McMurray (4)	37,500	20,000	(15,000)	—	42,500
Vincent J. Osterman (5)	50,000	—	—	(50,000)	—

(1) Mr. Krimbill vested in 100,000 Service Awards on July 9, 2018. He was granted 300,000 Service Awards on November 21, 2018, of which 75,000 vests on each of February 11, 2020, November 10, 2020, February 11, 2021 and November 12, 2021, respectively.

(2) Mr. Karlovich vested in 12,500 and 12,500 Service Awards on November 13, 2018 and February 12, 2019, respectively. He was granted 25,000 Service Awards on November 21, 2018, of which 12,500 vests on each of February 11, 2021 and November 12, 2021, respectively.

(3) Mr. Thuillier vested in Service Awards of 11,551 on September 11, 2018, 5,000 on November 13, 2018 and 5,000 on February 12, 2019. He was granted 11,551 Service Awards on September 11, 2018 and 10,000 Service Awards on November 21, 2018, of which 5,000 vests on each of February 11, 2021 and November 12, 2021, respectively.

(4) Mr. McMurray vested in 7,500 and 7,500 Service Awards on November 13, 2018 and February 12, 2019, respectively. He was granted 20,000 Service Awards on November 21, 2018, of which 10,000 vests on each of February 11, 2021 and November 12, 2021, respectively.

(5) Mr. Osterman forfeited 50,000 Service Awards on July 9, 2018 upon termination of his employment related to the sale of virtually all of our remaining Retail Propane segment on July 10, 2018. Mr. Osterman did not receive any Service Awards in fiscal year 2019 prior to the termination of his employment.

The Service Award units granted to the named executive officers were determined by reference to our peer group and the market-based benchmarks compiled by PM&P and were based on the named executive officers total compensation falling between the 25th and 50th percentile of the peer group.

The Service Award units granted on November 21, 2018 were intended as a discretionary bonus for performance during fiscal year ended March 31, 2018.

The following table summarizes the vesting dates of the unvested Service Award units at March 31, 2019 (as noted above, Mr. Osterman forfeited all unvested Service Award units in connection with the termination of his employment on July 10, 2018):

	Service Award Units Vesting By Fiscal Year Ending			Unvested Units at
Name	March 31, 2020	March 31, 2021	March 31, 2022	March 31, 2019
H. Michael Krimbill (1)	175,000	150,000	75,000	400,000
Robert W. Karlovich III (2)	25,000	25,000	12,500	62,500
Lawrence J. Thuillier (2)	10,000	10,000	5,000	25,000
Kurston P. McMurray (3)	15,000	17,500	10,000	42,500

(1) Mr. Krimbill's Service Awards will vest as follows: For the fiscal year ending March 31, 2020, 100,000 of the units will vest on July 8, 2019 and 75,000 of the units will vest on February 11, 2020. For the fiscal year ending March 31, 2021, half of the units will vest on November 10, 2020 and February 11, 2021. For the fiscal year ending March 31, 2022, the units will vest on November 12, 2021.

(2) Mr. Karlovich's and Mr. Thuillier's Service Awards will vest as follows: For the fiscal year ending March 31, 2020, half of the units will vest on November 13, 2019 and the other half on February 11, 2020. For the fiscal year ending March 31, 2021, half of the units will vest on November 10, 2020 and February 11, 2021. For the fiscal year ending March 31, 2022, the units will vest on November 12, 2021.

(3) Mr. McMurray's Service Awards will vest as follows: For the fiscal year ending March 31, 2020, half of the units will vest on November 13, 2019 and the other half on February 11, 2020. For the fiscal year ending March 31, 2021, 7,500 of the units will vest on

November 10, 2020 and 10,000 of the units will vest on February 11, 2021. For the fiscal year ending March 31, 2022, the units will vest on November 12, 2021.

Beginning in April 2015, our general partner granted units that vest contingent both on the continued service of the recipients through the vesting date and also on the performance of our common units relative to other peer entities in the Alerian MLP Index (the “Index”) over specified periods of time (the “Performance Awards”). These Performance Award units were granted to certain employees. Performance was to be calculated based on the return on our common units (including changes in the market price of the common units and distributions paid during the performance period) relative to the returns on the common units of the other entities in the Index. During the three months ended December 31, 2018, the compensation committee of the board of directors of our general partner terminated the Performance Award plan and all unvested outstanding Performance Awards units were canceled. Accordingly, as no replacement awards were granted, all previously unrecognized compensation cost was expensed as of the cancellation date.

Severance and Change in Control Benefits

We do not provide any severance or change of control benefits to our named executive officers, other than to Mr. McMurray, who is entitled to receive severance benefits pursuant to his employment agreement in the event of certain terminations of his employment (as described below after the “Summary Compensation Table” under the heading, “Employment Agreement with Mr. McMurray”). The board of directors has the option to accelerate the vesting of the restricted units in the event of a change in control of the Partnership, although it is not under any obligation to do so. If the board of directors were to exercise its discretion to accelerate the vesting of restricted units upon a change in control, the value of such units would be the same as reported in the “Outstanding Equity Awards at March 31, 2019” table below (in the “Market Value of Service Award Units that Have Not Yet Vested” column).

401(k) Plan

We have established a defined contribution 401(k) plan to assist our eligible employees in saving for retirement on a tax-deferred basis. The 401(k) plan permits all eligible employees, including our named executive officers, to make voluntary pre-tax contributions to the plan, subject to applicable tax limitations. For every dollar that employees contribute up to 1% of their eligible compensation (as defined in the plan), we contribute one dollar, plus 50 cents for every dollar employees contribute between 1% and 6% of their eligible compensation (as defined in the plan). Our matching contributions prior to January 1, 2015 vest over five years and, effective January 1, 2015, our matching contributions vest over two years.

Other Benefits

We do not maintain a defined benefit or pension plan for our executive officers, because we believe such plans primarily reward longevity rather than performance. We provide a basic benefits package available to substantially all full-time employees, which includes a 401(k) plan and medical, dental, vision, disability and life insurance.

Other Officers

Certain officers who have leadership roles within our individual business units, but who are not executive officers, participate in formulaic bonus programs that are based on the performance of the individual business units with which they are involved. In most cases, similar programs were in place prior to our acquisition of the businesses, and we have left the programs substantially intact.

Competitive Review and Fiscal Year 2019 Compensation Program

During fiscal year 2019, PM&P conducted a competitive review of our executive compensation program and provided input to the compensation committee regarding competitive compensation levels and compensation program design. In order to provide guidance to the compensation committee regarding competitive rates of compensation, PM&P collected pay data from the following sources:

- Compensation surveys including data from published compensation surveys representative of other energy industry and broader general industry companies with revenues of between $1 billion and $6 billion; and
- Peer group data including pay data from 10-K and proxy filings for a group of 18 publicly traded midstream oil & gas partnerships of similar size and scope to us.

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Compensation Peer Group Companies

AmeriGas Partners LP	NuStar Energy L.P.	Martin Midstream Partners LP
Ferrellgas Partners LP	Targa Resources Corp.	Boardwalk Pipeline Partners, LP
Star Group, L.P.	Buckeye Partners, L.P.	Western Gas Partners LP
Suburban Propane Partners, L.P.	Genesis Energy LP	EnLink Midstream Partners, LP
ONEOK Partners, L.P.	Crestwood Equity Partners LP	
Williams Partners L.P.	Magellan Midstream Partners LP	
Enbridge Energy Partners, L.P.	DCP Midstream Partners LP	

PM&P defines "market" as the combination of survey data and peer group data. As described above, the compensation committee considered this data in establishing salaries for fiscal year 2019 and in determining the number of Service Award units to grant to the named executive officers.

Employment Agreements

We do not have employment agreements with any of our named executive officers, other than Mr. McMurray (as described below after the "Summary Compensation Table" under the heading, "Employment Agreement with Mr. McMurray").

Deductibility of Compensation

We believe that the compensation paid to the named executive officers is generally fully deductible for federal income tax purposes. We are a limited partnership and do not meet the definition of a "corporation" subject to deduction limitations under Section 162(m) of the Internal Revenue Code of 1986, as amended.

Compensation Committee Report

The compensation committee of the board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above with management. Based on this review and discussion, the compensation committee recommended to the board of directors of our general partner that the Compensation Discussion and Analysis be included in this Annual Report.

Members of the Compensation Committee:

Stephen L. Cropper (Chairman)
Bryan K. Guderian
James C. Kneale

Relation of Compensation Policies and Practices to Risk Management

Our compensation arrangements contain a number of design elements that serve to minimize the incentive for taking excessive or inappropriate risk to achieve short-term, unsustainable results. This includes using restricted unit grants as a significant element of executive compensation, as the restricted units are designed to reward the executive officers based on the long-term performance of the Partnership. In combination with our risk management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Compensation Committee Interlocks and Insider Participation

During fiscal year 2019, Stephen L. Cropper, Bryan K. Guderian, and James C. Kneale served on the compensation committee. None of these individuals is an employee or an officer of our general partner. As described under Part I, Item 13–"Transactions With Related Persons," Mr. Guderian is an executive officer of WPX, and we entered into certain transactions with WPX during fiscal year 2019. Shawn W. Coady was an executive officer and is still a member of the board of directors of our general partner. Dr. Coady also serves on the board of directors of HOH, a family-owned company, and in this capacity Dr. Coady participates in the compensation setting process of the HOH board of directors.

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Summary Compensation Table for 2019

The following table summarizes the compensation earned by our named executive officers for fiscal years 2017 through 2019.

Name and Position	Fiscal Year	Salary ($)	Bonus ($)	Restricted Unit Awards (Service and Performance Awards) (1) ($)	All Other Compensation (2) ($)	Total ($)
H. Michael Krimbill	2019	614,423	1,000,000	1,928,520	13,886	3,556,829
Chief Executive Officer	2018	350,000	—	—	10,891	360,891
	2017	350,000	—	7,174,094	10,463	7,534,557
Robert W. Karlovich III	2019	483,846	650,000	142,405	7,695	1,283,946
Executive Vice President and	2018	428,846	430,000	711,291	9,079	1,579,216
Chief Financial Officer	2017	400,000	—	809,985	5,510	1,215,495
Lawrence J. Thuillier	2019	267,693	—	191,964	9,639	469,296
Chief Accounting Officer	2018	259,615	—	414,525	9,357	683,497
	2017	250,000	—	374,007	43,469	667,476
Kurston P. McMurray (3)	2019	348,077	650,000	113,924	9,199	1,121,200
Executive Vice President and	2018	298,077	300,000	426,774	8,182	1,033,033
General Counsel and Secretary						
Vincent J. Osterman (4)	2019	98,500	—	—	32,323	130,823
Former President,	2018	312,500	—	569,032	44,926	926,458
Retail Propane Operations	2017	250,000	—	1,662,027	36,831	1,948,858

(1) The fair values of the restricted units shown in the table above were calculated based on the closing market prices of our common units on the grant dates, with adjustments made to reflect the fact that the restricted units are not entitled to distributions during the vesting period. The impact of the lack of distribution rights during the vesting period was estimated using the value of the most recent distribution prior to the grant date and assumptions that a market participant might make about future distribution growth. This calculation of fair value is consistent with the provisions of Accounting Standards Codification ("ASC") 718 Stock Compensation. For fiscal years 2018 and 2017, this column also includes the value of Performance Awards granted, prior to the termination of the Performance Award plan.

(2) The amounts in this column include matching contributions to our 401(k) plan. Amount for Mr. Thuillier for fiscal year 2017 includes moving expenses. Amounts for Mr. Osterman include propane provided to him and members of his family (valued for the purpose at the cost of the propane to NGL). The following table summarizes these amounts for Mr. Thuillier and Mr. Osterman:

Name	Fiscal Year	401(k) Match	Moving Expenses	Propane	Total Other Compensation
Lawrence J. Thuillier	2017	$ 5,721	$ 37,748	$ —	$ 43,469
Vincent J. Osterman	2019	$ 3,758	$ —	$ 28,565	$ 32,323
	2018	$ 6,273	$ —	$ 38,653	$ 44,926
	2017	$ 5,721	$ —	$ 31,110	$ 36,831

(3) Mr. McMurray was not a named executive officer prior to fiscal year 2018.

(4) Mr. Osterman resigned from employment in conjunction with the sale of virtually all of our remaining Retail Propane segment on July 10, 2018.

Employment Agreement with Mr. McMurray

Mr. McMurray is party to an employment agreement with the Partnership, dated March 10, 2017. The agreement has a term of five years from the effective date, subject to automatic renewals for one-year periods thereafter unless either party provides 60 days' notice of non-renewal of the term. The agreement provides that Mr. McMurray will receive a base salary of no less than $250,000 per year and will be eligible to receive an annual bonus with respect to each fiscal year of the Partnership at a target of 100% of his base salary. Mr. McMurray is also entitled to receive annual awards of unvested units under the Partnership's LTIP.

In the event that Mr. McMurray's employment is terminated by the Partnership without "cause" (as defined in his agreement), provided that he executes a general release of claims, Mr. McMurray is entitled to receive (i) continued payment of his base salary for 12 months following the termination, (ii) the guaranteed unit awards that would have been paid or granted to Mr. McMurray had Mr. McMurray remained employed for an additional three years following his termination, and (iii) his target annual bonus for the performance year in which his termination occurs. Mr. McMurray would also be entitled to receive the severance benefits described in the foregoing sentence in the event that he voluntarily resigns due to a "constructive discharge," which circumstances would include (1) a reduction of Mr. McMurray's annual base salary below $250,000 (other than an across-the-board, pro rata reduction of no more than 10% applicable to all similarly situated executive officers of the Partnership) or the Partnership's failure to provide Mr. McMurray's elements of compensation, (2) the removal of Mr. McMurray from the position of Executive Vice President and General Counsel and Secretary without Mr. McMurray's written consent, (3) any action by the Partnership that results in significant diminution of Mr. McMurray's authority, power or responsibilities, or (4) the Partnership's relocation of its principal place of business in Oklahoma to a location more than 50 miles from its current location. Mr. McMurray is subject to non-disclosure and intellectual property rights assignment obligations, and an obligation not to solicit customers, employees or consultants lasting during his employment and for a period of 12 months thereafter.

Restricted Unit Awards

During fiscal year 2019, the compensation committee granted awards for which units vest at specified dates, contingent only on the continued service of the recipient through the service date (the "Service Awards").

2019 Grants of Plan Based Awards Table

The following table summarizes the number of restricted Service Award units granted to our named executive officers, and their grant date fair values:

Name	Grant Date	Total Number of Service Award Units	Grant Date Fair Value of Service Award Units ($)(1)
H. Michael Krimbill	November 21, 2018	300,000	1,928,520
Robert W. Karlovich III	November 21, 2018	25,000	142,405
Lawrence J. Thuillier	September 11, 2018	11,551	135,002
	November 21, 2018	10,000	56,962
Kurston P. McMurray	November 21, 2018	20,000	113,924
Vincent J. Osterman (2)	—	—	—

(1) The fair value of the restricted Service Award units shown in the table above was calculated based on the closing market price of our common units on the grant dates, with adjustments made to reflect the fact that restricted units are not entitled to distributions during the vesting period.

(2) Mr. Osterman did not receive any restricted Service Award units in fiscal year 2019 prior to the termination of his employment on July 10, 2018.

We record the expense for each Service Award on a straight-line basis over the requisite period for the entire award (that is, over the requisite service period of the last separately vesting portion of the award), ensuring that the amount of compensation cost recognized at any date at least equals the portion of the grant-date value of the award that is vested at that date. The amounts reported in the table above for restricted units is the grant date fair value for financial reporting purposes under ASC 718 and does not represent the amount actually realized by the named executive officer at vesting, which may be more or less than the amount reported in the table above.

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Outstanding Equity Awards at March 31, 2019

The following table summarizes the number of unvested Service Awards outstanding and their fair values at March 31, 2019:

Name	Number of Service Award Units that Have Not Yet Vested (#)(1)	Market Value of Service Award Units that Have Not Yet Vested ($)(2)
H. Michael Krimbill	400,000	5,612,000
Robert W. Karlovich III	62,500	876,875
Lawrence J. Thuillier	25,000	350,750
Kurston P. McMurray	42,500	596,275
Vincent J. Osterman (3)	—	—

(1) Reflects Service Awards that have not vested and are held by each named executive officer.

(2) Calculated based on the closing market price of our common units at March 31, 2019 of $14.03. No adjustments were made to reflect the fact that the restricted units are not entitled to distributions during the vesting period.

(3) Mr. Osterman forfeited all outstanding equity awards in connection with the termination of his employment on July 10, 2018.

2019 Units Vested

During fiscal year 2019, certain of the restricted Service Awards vested. The following table summarizes the value of the awards on the vesting date which was calculated based of the closing market price per common unit on the vesting dates.

Name	Number of Service Award Units Acquired on Vesting (#)	Value Realized on Vesting ($)
H. Michael Krimbill (1)	100,000	1,247,500
Robert W. Karlovich III (2)	25,000	272,375
Lawrence J. Thuillier (3)	21,551	243,952
Kurston P. McMurray (4)	15,000	163,425
Vincent J. Osterman (5)	—	—

(1) Mr. Krimbill vested in 100,000 Service Awards on July 9, 2018.

(2) Mr. Karlovich vested in 12,500 and 12,500 Service Awards on November 13, 2018 and February 12, 2019, respectively.

(3) Mr. Thuillier vested in 11,551, 5,000 and 5,000 Service Awards on September 11, 2018, November 13, 2018 and February 12, 2019, respectively.

(4) Mr. McMurray vested in 7,500 and 7,500 Service Awards on November 13, 2018 and February 12, 2019, respectively.

(5) Mr. Osterman did not vest in any Service Awards prior to the termination of his employment on July 10, 2018.

Upon vesting, certain of the named executive officers elected for us to remit payments to taxing authorities in lieu of issuing common units. The following table summarizes the number of common units issued and the number of common units withheld for taxes:

Name	Number of Units Issued	Number of Units Withheld	Total
Robert W. Karlovich III	13,870	11,130	25,000
Lawrence J. Thuillier	12,589	8,962	21,551
Kurston P. McMurray	8,099	6,901	15,000

Potential Payments Upon Termination or Change in Control

We do not provide any severance or change of control benefits to our named executive officers , other than Mr. McMurray, who is entitled to receive severance benefits for certain types of terminations (as described in more detail above under the heading, “Employment Agreement with Mr. McMurray”). In the event that Mr. McMurray’s employment had been terminated as of March 31, 2019 by the Partnership without "cause" or due to a "constructive discharge," Mr. McMurray would have been entitled to receive the following amounts:

Cash Severance		Value of Guaranteed Unit Awards		Target Annual Bonus		Total	
$	375,000	$	596,275	$	375,000	$	1,346,275

The board of directors has the option to accelerate the vesting of the restricted units in the event of a change in control of the Partnership, although it is not under any obligation to do so. If the board of directors were to exercise its discretion to accelerate the vesting of restricted units upon a change in control, the value of such units would be the same as reported in the "Outstanding Equity Awards at March 31, 2019" table above (in the "Market Value of Service Award Units that Have Not Yet Vested" column).

Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information regarding the ratio of the annual total compensation of our Chief Executive Officer, Mr. Krimbill, to the median of the annual total compensation of our employees for our last fiscal year.

For the year ended March 31, 2019:

- The median of the annual total compensation of all employees (other than the Chief Executive Officer) was $46,408; and
- The annual total compensation of Mr. Krimbill, as reported in the Summary Compensation Table above, was $3,556,829.

Based on the information for the year ended March 31, 2019, the ratio of the annual total compensation of our Chief Executive Officer to the annual total compensation of our median employee was approximately 77 to 1.

To determine our median employee, we identified each individual employed by us on January 1, 2019, our determination date. As of that date, we had 1,210 employees located in two countries. We identified the median employee by examining only base pay plus overtime for the period from January 1, 2018 through December 31, 2018. We included all employees, with the exception of three employees that work in Canada, whether employed on a full-time or part-time basis, and did not make any estimates, assumptions or adjustments to any base pay plus overtime amounts. After identifying the median employee, we calculated the annual total compensation for the median employee using the same methodology we use to calculate total annual compensation for our named executive officers, as set forth in the Summary Compensation Table above.

This pay ratio is a reasonable estimate calculated in a manner consistent with SEC rules based on our payroll and employment records and the methodology described above. The SEC rules for identifying the median employee and calculating the pay ratio based on that employee's annual total compensation allow companies to adopt a variety of methodologies, to apply certain exclusions, and to make reasonable estimates and assumptions that reflect their compensation practices. As such, the pay ratio reported by other companies may not be comparable to the pay ratio reported above, as other companies may have different employment and compensation practices and may utilize different methodologies, exclusions, estimates and assumptions in calculating their own pay ratios.

Director Compensation

Officers or employees of our general partner or its affiliates who also serve as directors do not receive additional compensation for their service as a director of our general partner. Each director who is not an officer or employee of our general partner or its affiliates receives the following cash compensation for his board service:

- an annual retainer of $60,000;
- an annual retainer of $10,000 for the chairmen of the audit and compensation committees; and
- an annual retainer of $5,000 for each member of the audit and compensation committees other than the chairman.

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Special committees are convened by the board of directors from time to time to review specific transactions. Compensation paid to the members of these committees varies depending on the transaction and the expected time commitment of the committee members.

Effective on March 29, 2019, the board of directors approved the following changes to the compensation for each director who is not an officer or employee of our general partner or its affiliates:

- an annual retainer of $80,000;
- an annual retainer of $20,000 for the chairman of the audit committee;
- an annual retainer of $15,000 for the chairman of the compensation committee;
- an annual retainer of $14,000 for each member of the audit committee other than the chairman; and
- an annual retainer of $10,000 for each member of the compensation committee other than the chairman.

In addition, each director who is not an officer or employee of our general partner or its affiliates (with the exception of Dr. Coady) has been granted awards of restricted units. All of our directors are also reimbursed for all out-of-pocket expenses incurred in connection with attending board or committee meetings. Each director is indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

The following table summarizes the compensation earned during fiscal year 2019 by each director who is not an officer or employee of our general partner or its affiliates:

Name	Fees Earned or Paid in Cash ($)	Restricted Unit Awards ($)	Total ($)
Shawn W. Coady	40,000	—	40,000
James M. Collingsworth	75,000	45,569	120,569
Stephen L. Cropper	85,000	45,569	130,569
Bryan K. Guderian	75,000	45,569	120,569
James C. Kneale	85,000	45,569	130,569

Long-Term Equity Incentive Awards

The following table summarizes Service Award units granted and vested during fiscal year 2019 with respect to each director who is not an officer or employee of our general partner or its affiliates:

Name	Unvested Units at March 31, 2018	Units Granted	Units Vested	Unvested Units at March 31, 2019
Shawn W. Coady (1)	40,000	—	(20,000)	20,000
James M. Collingsworth (2)	24,000	8,000	(8,000)	24,000
Stephen L. Cropper (2)	24,000	8,000	(8,000)	24,000
Bryan K. Guderian (2)	24,000	8,000	(8,000)	24,000
James C. Kneale (3)	20,000	8,000	(8,000)	20,000

(1) Dr. Coady vested in 20,000 Service Awards on July 9, 2018. These units were granted to Dr. Coady while in his role as our President and Chief Operating Officer, Retail Division. Dr. Coady was allowed to retain his unvested units when we sold a portion of our Retail Propane segment to DCC LPG ("DCC"). Dr. Coady did not receive any Service Awards in fiscal year 2019 prior to the termination of his employment.

(2) Mr. Collingsworth, Mr. Cropper and Mr. Guderian vested in 8,000 Service Awards on July 9, 2018. Mr. Collingsworth, Mr. Cropper and Mr. Guderian were granted 8,000 Service Awards on November 21, 2018, of which 4,000 vests on each of February 11, 2021 and November 12, 2021, respectively.

(3) Mr. Kneale vested in 4,000 Service Awards on November 13, 2018 and 4,000 Service Awards on February 12, 2019. Mr. Kneale was granted 8,000 Service Awards on November 21, 2018, of which 4,000 vests on each of February 11, 2021 and November 12, 2021, respectively.

The following table summarizes the vesting dates of the unvested Service Award units at March 31, 2019:

	Service Award Units Vesting By Fiscal Year Ending			Unvested Units at
Name	March 31, 2020	March 31, 2021	March 31, 2022	March 31, 2019
Shawn W. Coady (1)	20,000	—	—	20,000
James M. Collingsworth (2)	12,000	8,000	4,000	24,000
Stephen L. Cropper (2)	12,000	8,000	4,000	24,000
Bryan K. Guderian (2)	12,000	8,000	4,000	24,000
James C. Kneale (3)	8,000	8,000	4,000	20,000

(1) Dr. Coady's Service Awards will vest on July 8, 2019.

(2) Mr. Collingsworth's, Mr. Cropper's and Mr. Guderian's Service Awards will vest as follows: For the fiscal year ending March 31, 2020, 8,000 of the units will vest on July 8, 2019 and 4,000 of the units will vest on February 11, 2020. For the fiscal year ending March 31, 2021, half of the units will vest on November 10, 2020 and February 11, 2021. For the fiscal year ending March 31, 2022, the units will vest on November 12, 2021.

(3) Mr. Kneale's Service Awards will vest as follows: For the fiscal year ending March 31, 2020, half of the units will vest on July 8, 2019 and February 11, 2020. For the fiscal year ending March 31, 2021, half of the units will vest on November 10, 2020 and February 11, 2021. For the fiscal year ending March 31, 2022, the units will vest on November 12, 2021.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Security Ownership of Certain Beneficial Owners and Management

The following table summarizes the beneficial ownership, as of May 28, 2019, of our common units by:

- each person or group of persons known by us to be a beneficial owner of more than 5% of our outstanding common units;
- each director of our general partner;
- each named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

Beneficial Owners	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (1)
5% or greater unitholders (other than officers and directors):		
OppenheimerFunds, Inc. (2)	20,250,603	16.08%
ALPS Advisors, Inc. (3)	10,867,760	8.63%
Directors and named executive officers:		
Shawn W. Coady (4)	2,578,195	2.05%
James M. Collingsworth (5)	108,620	*
Stephen L. Cropper (6)	51,000	*
Bryan K. Guderian	48,500	*
Robert W. Karlovich III (7)	59,533	*
James C. Kneale (8)	52,000	*
H. Michael Krimbill (9)	2,382,820	1.89%
Kurston P. McMurray (10)	28,594	*
Vincent J. Osterman (11)	3,983,730	3.16%
John T. Raymond (12)	226,634	*
L. John Schaufele IV	—	*
Lawrence J. Thuillier (13)	32,368	*
All directors and named executive officers as a group (12 persons) (14)	9,551,994	7.58%

* Less than 1.0%

(1) Based on 125,966,868 common units outstanding at May 28, 2019.

(2) The mailing address for OppenheimerFunds, Inc. is 225 Liberty Street, New York, NY 10281. OppenheimerFunds, Inc. reported shared voting and dispositive power with respect to all common units beneficially owned. The information related to OppenheimerFunds, Inc. is based upon its Schedule 13F filed with the SEC for the quarter ended March 31, 2019.

(3) The mailing address for ALPS Advisors, Inc. is 1290 Broadway, Suite 1100, Denver, CO 80203. ALPS Advisors, Inc. reported shared voting and dispositive power with respect to all common units beneficially owned. The information related to ALPS Advisors, Inc. is based upon its Schedule 13F filed with the SEC for the quarter ended March 31, 2019.

(4) Dr. Coady owns 98,304 of these common units, which includes 20,000 unvested units that will vest on July 8, 2019. SWC Family Partnership LP owns 2,320,391 of these common units. SWC Family Partnership LP is solely owned by SWC General Partner, LLC, of which Dr. Coady is the sole member. Dr. Coady may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. The 2012 Shawn W. Coady Irrevocable Insurance Trust, which was established for the benefit of Shawn W. Coady's children, owns 135,000 of these common units. Dr. Coady may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. The Tara Nicole Coady Trust II, of which the reporting person is the trustee, owns 12,250 common units. The Colleen Blair Coady Trust, of which the reporting person is the trustee, owns 12,250 common units. Dr. Coady also owns a 12.27% interest in our general partner through Coady Enterprises, LLC, of which he owns 100% of the membership interests.

(5) Mr. Collingsworth owns 103,500 of these common units. Mr. Collingsworth holds 2,000 of these common units jointly with his spouse, Cindy Collingsworth. Cindy Collingsworth and her sister jointly own 2,250 of these common units. Cindy Collingsworth owns 870 of these common units

(6) Mr. Cropper owns 26,000 of these common units. The Donna L. Cropper Living Trust, of which Mr. Cropper and his spouse, Donna L. Cropper, are the trustees, owns 25,000 of these common units.

(7) Does not include 12,500 unvested units that will vest on November 13, 2019, 12,500 unvested units that will vest on February 11, 2020, 12,500 unvested units that will vest on November 10, 2020, 12,500 unvested units that will vest on February 11, 2021 and 12,500 unvested units that will vest on November 12, 2021.

(8) Units are held in The Suzanne and Jim Kneale Living Trust, of whom Mr. Kneale and his wife are trustees.

(9) Mr. Krimbill owns 831,417 of these common units, which includes 100,000 unvested units that will vest on July 8, 2019 and does not include 75,000 unvested units that will vest on February 11, 2020, 75,000 unvested units that will vest on November 10, 2020, 75,000 unvested units that will vest on February 11, 2021 and 75,000 unvested units that will vest on November 12, 2021. All of the unvested units noted above were reported on Mr. Krimbill's Form 4. Krim2010, LLC owns 904,848 of these common units. Krimbill Enterprises LP, H. Michael Krimbill and James E. Krimbill own 90.89%, 4.05%, and 5.06% of Krim2010, LLC, respectively. Krimbill Enterprises LP also owns 283,000 of these common units. Krimbill Enterprises LP is controlled by H. Michael Krimbill via his ownership of its general partner, Krimbill Holding Company. H. Michael Krimbill may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. KrimGP2010 LLC owns 363,555 of these common units. KrimGP2010 LLC is solely owned by H. Michael Krimbill. H. Michael Krimbill may be deemed to have sole voting and investment power over these units. H. Michael Krimbill also owns a 14.81% interest in our general partner through KrimGP2010, LLC, of which he owns 100% of the membership interests and Krimbill Capital Group, LLC, which is owned 100% by the H. Michael Krimbill Revocable Trust, of which Mr. Krimbill is the trustee.

(10) Does not include 7,500 unvested units that will vest on November 13, 2019, 7,500 unvested units that will vest on February 11, 2020, 7,500 unvested units that will vest on November 10, 2020, 10,000 unvested units that will vest on February 11, 2021 and 10,000 unvested units that will vest on November 12, 2021.

(11) Mr. Osterman resigned from the board of directors effective January 22, 2019 and the information that follows is based on his last filed Form 4. Mr. Osterman owns 129,093 of these common units. The remaining common units are owned by AO Energy, Inc. (110,587 common units), E. Osterman, Inc. (394,350 common units), E. Osterman Gas Services, Inc. (301,700 common units), E. Osterman Propane, Inc. (669,300 common units), Milford Propane, Inc. (559,784 common units), Osterman Family Foundation (122,016 common units), Osterman Propane, Inc. (1,445,850 common units), Propane Gas, Inc. (36,450 common units) and Saveway Propane Gas Service, Inc. (214,600 common units). Each of these holding entities may be deemed to have sole voting and investment power over its own common units and Propane Gas, LLC, as sole shareholder of Propane Gas, Inc., may be deemed to have sole voting and investment power over those common units. Vincent J. Osterman is a director, executive officer and shareholder or member of each of these entities and may be deemed to have sole voting and investment power over 798,393 common units and shared voting and investment power (with his father, Ernest Osterman) over 3,185,337 common units, but disclaims beneficial ownership except to the extent of his pecuniary interest therein. Vincent J. Osterman also owns a 1.65% interest in our general partner through VE Properties XI LLC.

(12) Mr. Raymond owns 50,000 of these common units. EMG NGL HC, LLC owns 176,634 of these common units. John T. Raymond is the Chief Executive Officer and Managing Partner of NGP MR GP LLC, the general partner of NGP MR, LP, the general partner of NGP Midstream & Resources, LLC, a member holding a majority interest in EMG NGL HC LLC. John T. Raymond may be deemed to have shared voting and investment power over these units, but disclaims beneficial ownership except to the extent of his pecuniary interest therein. EMG I NGL GP Holdings, LLC, an affiliate of EMG NGL HC LLC, owns a 5.73% interest in our general partner. EMG II NGL GP Holdings, LLC, an affiliate of EMG NGL HC LLC, owns a 5.36% interest in our general partner.

(13) Does not include 5,000 unvested units that will vest on November 13, 2019, 5,000 unvested units that will vest on February 11, 2020, 5,000 unvested units that will vest on November 10, 2020, 5,000 unvested units that will vest on February 11, 2021 and 5,000 unvested units that will vest on November 12, 2021.

(14) The directors and executive officers of our general partner also collectively own a 58.58% interest in our general partner.

Unless otherwise noted, each of the individuals listed above is believed to have sole voting and investment power with respect to the units beneficially held by them. The mailing address for each of the officers and directors of our general partner listed above is 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136.

Securities Authorized for Issuance Under Equity Compensation Plan

The following table summarizes information regarding the securities that may be issued under the LTIP at March 31, 2019.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuances Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)(1)
Equity Compensation Plans Approved by Security Holders	—	—	—
Equity Compensation Plans Not Approved by Security Holders (2)	2,308,400	—	—
Total	2,308,400	—	—

(1) The number of common units that may be delivered pursuant to awards under the LTIP is limited to 10% of our issued and outstanding common units. The maximum number of common units deliverable under the LTIP automatically increases to 10% of the issued and outstanding common units immediately after each issuance of common units, unless the plan administrator determines to increase the maximum number of units deliverable by a lesser amount.

(2) Our general partner adopted the LTIP in connection with the completion of our initial public offering ("IPO") in May 2011. The adoption of the LTIP did not require the approval of our unitholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Our directors, executive officers, and greater than 5% unitholders collectively own an aggregate of 40,670,357 common units, representing an aggregate 32.29% limited partner interest in us. In addition, our general partner owns a 0.1% general partner interest in us and all of our incentive distribution rights ("IDRs").

Distributions and Payments to Our General Partner and Its Affiliates

Our general partner and its affiliates do not receive any management fee or other compensation for the management of our business and affairs, but they are reimbursed for all expenses that they incur on our behalf, including general and administrative expenses. Our general partner determines the amount of these expenses. In addition, our general partner owns the 0.1% general partner interest and all of the IDRs. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement.

The following table summarizes the distributions and payments to be made by us to our directors, officers, and greater than 5% owners and our general partner in connection with our ongoing operation and any liquidation. These distributions and payments were determined by and among affiliated entities before our IPO and, consequently, are not the result of arm's length negotiations.

Operation Stage

Distributions of available cash to our directors, officers, and greater than 5% owners and our general partner	We generally make cash distributions 99.9% to our unitholders pro rata, including our directors, officers, and greater than 5% owners as the holders of an aggregate 40,670,357 common units, and 0.1% to our general partner. In addition, when distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner is entitled to increasing percentages of the distributions, up to 48.1% of the distributions above the highest target distribution level.
	Assuming we have sufficient available cash to pay the same quarterly distribution on all of our outstanding units for four quarters that we paid in May 2019 ($0.39 per unit), our general partner would receive an annual distribution of $0.2 million on its general partner interest and incentive distribution rights, and our directors, officers, and greater than 5% owners would receive an aggregate annual distribution of $72.6 million on their common units.
	If our general partner elects to reset the target distribution levels, it will be entitled to receive common units and to maintain its general partner interest.
Payments to our general partner and its affiliates	Our general partner and its affiliates do not receive any management fee or other compensation for the management of our business and affairs, but they are reimbursed for all expenses that they incur on our behalf, including general and administrative expenses. As the sole purpose of the general partner is to act as our general partner, substantially all of the expenses of our general partner are incurred on our behalf and reimbursed by us or our subsidiaries. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its IDRs will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Transactions With Related Persons

WPX

Bryan K. Guderian is a member of our board of directors and an executive officer of WPX. We purchase crude oil from and sell crude oil to WPX (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). We also treat and dispose of wastewater and solids received from WPX. The following table summarizes transactions with WPX for the year ended March 31, 2019 (in thousands):

Sales to WPX	$	28,026
Purchases from WPX	$	329,525

During the three months ended June 30, 2018, we entered into a definitive agreement with WPX. Under this agreement, we agreed to provide WPX the benefit of our minimum shipping fees or deficiency credits (fees paid in previous periods that were in excess of the volumes actually shipped) totaling $67.7 million at the time of the transaction (as discussed further in Note 2 to our consolidated financial statements included in this Annual Report), which can be utilized for volumes shipped that exceed the minimum monthly volume commitment in subsequent periods. We also agreed that we would only ship crude oil that we are required to purchase from WPX in utilizing our allotted capacity on these pipelines and they agreed to be fully responsible to us for all deficiency payments (money due when our actual shipments are less than our allotted capacity) for the remaining term of our contract, which totaled $50.3 million at June 30, 2018 (as discussed further in Note 9 to our consolidated financial statements included in this Annual Report). As consideration for this transaction, we paid WPX a net $35.3 million.

SemGroup

SemGroup holds an 11.78% ownership interest in our general partner. We sell product to and purchase product from SemGroup, and these transactions are included within revenues and cost of sales, respectively, in our consolidated statements of operations (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). We also lease crude oil storage from SemGroup. The following table summarizes transactions with SemGroup for the year ended March 31, 2019 (in thousands):

Sales to SemGroup	$	11,764
Purchases from SemGroup	$	15,045

DCC

Shawn W. Coady is a member of our board of directors and an executive officer of DCC. We sell propane to and purchase propane from DCC. We also lease trucks from DCC. The following table summarizes transactions with DCC for the year ended March 31, 2019 (in thousands):

Sales to DCC	$	14,676
Purchases from DCC	$	289

Other Transactions

We purchase goods and services from certain entities that are partially owned by our named executive officers and former named executive officer (Vincent J. Osterman). The following table summarizes these transactions for the year ended March 31, 2019:

Entity	Nature of Purchases	Amount Purchased		Ownership Interest in Entity
		(in thousands)		
Vincent J. Osterman				
VE Properties III, LLC	Office space rental	$	36	100%
H. Michael Krimbill				
Pinnacle Aviation 2007, LLC	Aircraft rental	$	216	50%
H. Michael Krimbill				
KAIR2014 LLC	Aircraft rental	$	211	50%

Timothy Osterman, a former employee of the Partnership, is the son of Vincent J. Osterman, who is a former executive officer of the Partnership and a former member of the board of directors and was an employee of the Partnership. Timothy Osterman resigned from the Partnership on July 10, 2018. Timothy Osterman received total compensation of approximately $0.4 million during the year ended March 31, 2019.

Travis Krimbill, an employee of the Partnership, is the son of H. Michael Krimbill, who is a named executive officer of the Partnership and a member of the board of directors. Travis Krimbill does not report to H. Michael Krimbill and his compensation is determined by the Chief Financial Officer. During the year ended March 31, 2019, Travis Krimbill received total compensation of approximately $0.1 million.

Registration Rights Agreement

We have entered into a registration rights agreement (as amended, the “Registration Rights Agreement”) with certain third parties (the “registration rights parties”) pursuant to which we agreed to register for resale under the Securities Act of 1933, as amended (“Securities Act”) common units owned by the parties to the Registration Rights Agreement. In connection with our IPO, we granted registration rights to the NGL Energy LP Investor Group, and subsequently, we have granted registration rights in connection with several acquisitions. We will not be required to register such common units if an exemption from the registration requirements of the Securities Act is available with respect to the number of common units desired to be sold. Subject to limitations specified in the Registration Rights Agreement, the registration rights of the registration rights parties include the following:

- *Demand Registration Rights.* Certain registration rights parties deemed “Significant Holders” under the agreement may, to the extent that they continue to own more than 4% of our common units, require us to file a registration statement with the SEC registering the offer and sale of a specified number of common units, subject to limitations on the number of requests for registration that can be made in any twelve-month period as well as customary cutbacks at the discretion of the underwriters relating to a potential offering. All other registration rights parties are entitled to notice of a Significant Holder’s exercise of its demand registration rights and may include their common units in such registration. We can only be required to file a total of nine registration statements upon the Significant Holders’ exercise of these demand registration rights and are only required to effect demand registration if the aggregate proposed offering price to the public is at least $10.0 million.
- *Piggyback Registration Rights.* If we propose to file a registration statement under the Securities Act to register our common units, the registration rights parties are entitled to notice of such registration and have the right to include their common units in the registration, subject to limitations that the underwriters relating to a potential offering may impose on the number of common units included in the registration. These counterparties also have the right to include their units in our future registrations, including secondary offerings of our common units.
- *Expenses of Registration.* With specified exceptions, we are required to pay all expenses incidental to any registration of common units, excluding underwriting discounts and commissions.

Review, Approval or Ratification of Transactions with Related Parties

The board of directors of our general partner has adopted a Code of Business Conduct and Ethics that, among other things, sets forth our policies for the review, approval and ratification of transactions with related persons. The Code of Business Conduct and Ethics provides that the board of directors of our general partner or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the Code of Business Conduct and Ethics provides that our officers will make all reasonable efforts to cancel or annul the transaction.

The Code of Business Conduct and Ethics provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to:

- whether there is an appropriate business justification for the transaction;
- the benefits that accrue to the Partnership as a result of the transaction;
- the terms available to unrelated third parties entering into similar transactions;
- the impact of the transaction on a director’s independence (in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer);
- the availability of other sources for comparable products or services;
- whether it is a single transaction or a series of ongoing, related transactions; and
- whether entering into the transaction would be consistent with the Code of Business Conduct and Ethics.

Director Independence

The NYSE does not require a listed publicly traded partnership like us to have a majority of independent directors on the board of directors of our general partner. For a discussion of the independence of the board of directors of our general partner, see Part III, Item 10–“Directors, Executive Officers and Corporate Governance –Board of Directors of our General Partner .”

Item 14. Principal Accounting Fees and Services

We have engaged Grant Thornton LLP as our independent registered public accounting firm. The following table summarizes fees we have paid Grant Thornton LLP to audit our annual consolidated financial statements and for other services for the periods indicated:

	March 31,	
	2019	2018
Audit fees (1)	$ 2,500,800	$ 2,507,000
Audit-related fees (2)	120,000	—
Tax fees	—	—
All other fees	3,500	—
Total	$ 2,624,300	$ 2,507,000

(1) Includes fees for audits of the Partnership's financial statements, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and the preparation of letters to underwriters and other requesting parties.

(2) Includes audits of financial statements for businesses divested during the fiscal year.

Audit Committee Approval of Audit and Non-Audit Services

The audit committee of the board of directors of our general partner has adopted a pre-approval policy with respect to services which may be performed by Grant Thornton LLP. This policy lists specific audit-related services as well as any other services that Grant Thornton LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional audit committee authorization. The audit committee receives quarterly reports on the status of expenditures pursuant to the pre-approval policy. The audit committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the audit committee prior to engagement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

1. *Financial Statements*. See the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. All schedules have been omitted because they are either not applicable, not required or the information required in such schedules appears in the financial statements or the related notes.
3. *Exhibits.*

Exhibit Number	Description
2.1	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, as the Representative, OWL Pearsall SWD, LLC, OWL Pearsall Holdings, LLC, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.2	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, as the Representative, OWL Karnes SWD, LLC, OWL Karnes Holdings, LLC, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.3	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, OWL Cotulla SWD, LLC, Terry Bailey, as trustee of the PJB Irrevocable Trust, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.4	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, OWL Nixon SWD, LLC, Terry Bailey, as trustee of the PJB Irrevocable Trust, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.4 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.5	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, HR OWL, LLC, OWL Operating, LLC, Lotus Oilfield Services, L.L.C., OWL Lotus, LLC, NGL Energy Partners, LP, High Sierra Water-Eagle Ford, LLC and High Sierra Transportation, LLC (incorporated by reference to Exhibit 2.5 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.6	Equity Interest Purchase Agreement, dated November 5, 2013, by and among NGL Energy Partners LP, High Sierra Energy, LP, Gavilon, LLC and Gavilon Energy Intermediate, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
2.7	Membership Interest Purchase Agreement, dated as of May 30, 2018, by and among NGL Energy Operating, LLC, NGL Energy Partners LP, and Superior Plus Energy Services Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 10, 2018)
3.1	Certificate of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-172186) filed with the SEC on April 15, 2011)
3.2	Certificate of Amendment to Certificate of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.2 to the Registration Statement on Form S-1 (File No. 333-172186) filed with the SEC on April 15, 2011)
3.3	Certificate of Formation of NGL Energy Holdings LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (File No. 333-172186) filed with the SEC on April 15, 2011)
3.4	Certificate of Amendment to Certificate of Formation of NGL Energy Holdings LLC (incorporated by reference to Exhibit 3.5 to the Registration Statement on Form S-1 (File No. 333-172186) filed with the SEC on April 15, 2011)
3.5	Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on February 28, 2013)
3.6	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC, dated as of August 6, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
3.7	Amendment No. 2 to Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC, dated as of June 27, 2014 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 3, 2014)
3.8	Amendment No. 3 to Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC, dated as of June 24, 2016 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 28, 2016)
3.9	Fourth Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP, dated as of June 13, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 13, 2017)
3.10	Fifth Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP, dated as of April 2, 2019 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on April 2, 2019)

Exhibit Number	Description
4.1	First Amended and Restated Registration Rights Agreement, dated October 3, 2011, by and among the Partnership, Hicks Oils & Hicksgas, Incorporated, NGL Holdings, Inc., Krim2010, LLC, Infrastructure Capital Management, LLC, Atkinson Investors, LLC, E. Osterman Propane, Inc. and the other holders party thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 7, 2011)
4.2	Amendment No. 1 and Joinder to First Amended and Restated Registration Rights Agreement dated as of November 1, 2011 by and among the Partnership and SemStream (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 4, 2011)
4.3	Amendment No. 2 and Joinder to First Amended and Restated Registration Rights Agreement, dated January 3, 2012, by and among NGL Energy Holdings LLC, Liberty Propane, L.L.C., Pacer-Enviro Propane, L.L.C., Pacer-Pittman Propane, L.L.C., Pacer-Portland Propane, L.L.C., Pacer Propane (Washington), L.L.C., Pacer-Salida Propane, L.L.C. and Pacer-Utah Propane, L.L.C. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on January 9, 2012)
4.4	Amendment No. 3 and Joinder to First Amended and Restated Registration Rights Agreement, dated May 1, 2012, by and between NGL Energy Holdings LLC and Downeast Energy Corp. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on May 4, 2012)
4.5	Amendment No. 4 and Joinder to First Amended and Restated Registration Rights Agreement, dated June 19, 2012, by and between NGL Energy Holdings LLC and NGP M&R HS LP LLC (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 25, 2012)
4.6	Amendment No. 5 and Joinder to First Amended and Restated Registration Rights Agreement, dated October 1, 2012, by and between NGL Energy Holdings LLC and Enstone, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 3, 2012)
4.7	Amendment No. 6 and Joinder to First Amended and Restated Registration Rights Agreement, dated November 13, 2012, by and between NGL Energy Holdings LLC and Gerald L. Jensen, Thrift Opportunity Holdings, LP, Jenco Petroleum Corporation, Caritas Trust, Animosus Trust and Nitor Trust (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 19, 2012)
4.8	Amendment No. 7 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of August 1, 2013, by and among NGL Energy Holdings LLC, Oilfield Water Lines, LP and Terry G. Bailey (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
4.9	Amendment No. 8 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of February 17, 2015, by and among NGL Energy Holdings LLC and Magnum NGL Holdco LLC (incorporated by reference to Exhibit 4.9 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.10	Amendment No. 9 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of February 25, 2016, by and among NGL Energy Holdings LLC and Magnum NGL Holdco LLC (incorporated by reference to Exhibit 4.10 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2016 filed with the SEC on May 31, 2016)
4.11	Registration Rights Agreement, dated December 2, 2013, by and among NGL Energy Partners LP and the purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
4.12	Indenture, dated as of October 24, 2016, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 24, 2016)
4.13	Forms of 7.5% Senior Notes due 2023 (incorporated by reference to Exhibit 4.2 and included as Exhibits A1 and A2 to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 24, 2016)
4.14	Registration Rights Agreement, dated as of October 24, 2016, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors listed therein on Exhibit A and Barclays Capital Inc. as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 24, 2016)
4.15	First Supplemental Indenture, dated as of February 21, 2017, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.8 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2018 filed with the SEC on February 11, 2019)
4.16	Second Supplemental Indenture, dated as of July 18, 2018, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.9 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2018 filed with the SEC on February 11, 2019)
4.17	Third Supplemental Indenture, dated as of January 25, 2019, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.10 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2018 filed with the SEC on February 11, 2019)
4.18	Indenture, dated as of February 22, 2017, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on February 22, 2017)
4.19	Forms of 6.125% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2 and included as Exhibits A1 and A2 to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on February 22, 2017)

Exhibit Number	Description
4.20	Registration Rights Agreement, dated as of February 22, 2017, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors listed therein on Exhibit A and RBC Capital Markets, LLC and Deutsche Bank Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on February 22, 2017)
4.21	First Supplemental Indenture, dated as of July 18, 2018, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2018 filed with the SEC on February 11, 2019)
4.22	Second Supplemental Indenture, dated as of January 25, 2019, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2018 filed with the SEC on February 11, 2019)
4.23	Indenture, dated as of April 9, 2019, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on April 9, 2019)
4.24	Forms of 7.50% Senior Notes due 2026 (incorporated by reference to Exhibit 4.2 and included as Exhibits A1 and A2 to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on April 9, 2019)
4.25	Registration Rights Agreement, dated as of April 9, 2019, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors listed therein on Exhibit A and RBC Capital Markets, LLC and Mizuho Securities USA LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on April 9, 2019)
4.26	Amended and Restated Guaranty Agreement, dated as of March 31, 2017 and effective as of December 31, 2016, among NGL Energy Partners LP and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended June 30, 2017 filed with the SEC on August 4, 2017)
10.1	Amended and Restated Credit Agreement, dated as of February 14, 2017, by and among NGL Energy Partners LP, NGL Energy Operating LLC, the subsidiary guarantors party thereto, Deutsche Bank Trust Company Americas, Deutsche Bank AG, New York Branch, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on February 15, 2017)
10.2	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of March 31, 2017, among the NGL Energy Partners LP, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on April 5, 2017)
10.3	Amendment No. 2 to Amended and Restated Credit Agreement, dated as of June 2, 2017, among the NGL Energy Partners LP, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 5, 2017)
10.4	Amendment No. 3 to Amended and Restated Credit Agreement, dated as of February 5, 2018, among NGL Energy Partners LP, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2017 filed with the SEC on February 9, 2018)
10.5	Amendment No. 4 to Amended and Restated Credit Agreement, dated as of March 6, 2018, among the Partnership, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on March 8, 2018)
10.6	Amendment No. 5 to Amended and Restated Credit Agreement, dated as of May 24, 2018, among the Partnership, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2018 filed with the SEC on May 30, 2018)
10.7	Amendment No. 6 to Amended and Restated Credit Agreement, dated as of July 5, 2018, among the Partnership, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 10, 2018)
10.8	Amendment No. 7 to Amended and Restated Credit Agreement, dated as of February 6, 2019, among the Partnership, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2018 filed with the SEC on February 11, 2019)
10.9	Common Unit Purchase Agreement, dated November 5, 2013, by and among NGL Energy Partners LP and the purchasers listed on Schedule A thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
10.10+	NGL Energy Partners LP 2011 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on May 17, 2011)
10.11+	Form of Restricted Unit Award Agreement under the NGL Energy Partners LP 2011 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended June 30, 2012 filed with the SEC on August 14, 2012)
21.1*	List of Subsidiaries of NGL Energy Partners LP

Exhibit Number	Description
23.1*	Consent of Grant Thornton LLP
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS**	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document

* Exhibits filed with this report.

** The following documents are formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets at March 31, 2019 and 2018, (ii) Consolidated Statements of Operations for the years ended March 31, 2019, 2018, and 2017, (iii) Consolidated Statements of Comprehensive Income (Loss) for the years ended March 31, 2019, 2018, and 2017, (iv) Consolidated Statements of Changes in Equity for the years ended March 31, 2019, 2018, and 2017, (v) Consolidated Statements of Cash Flows for the years ended March 31, 2019, 2018, and 2017, and (vi) Notes to Consolidated Financial Statements.

\+ Management contracts or compensatory plans or arrangements.

Item 16. Form 10-K Summary

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on May 30, 2019.

NGL ENERGY PARTNERS LP

By: NGL Energy Holdings LLC, its general partner

By: /s/ H. Michael Krimbill

H. Michael Krimbill

Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ H. Michael Krimbill	Chief Executive Officer and Director	May 30, 2019
H. Michael Krimbill	(Principal Executive Officer)	
/s/ Robert W. Karlovich III	Chief Financial Officer	May 30, 2019
Robert W. Karlovich III	(Principal Financial Officer)	
/s/ Lawrence J. Thuillier	Chief Accounting Officer	May 30, 2019
Lawrence J. Thuillier	(Principal Accounting Officer)	
/s/ Shawn W. Coady	Director	May 30, 2019
Shawn W. Coady		
/s/ James M. Collingsworth	Director	May 30, 2019
James M. Collingsworth		
/s/ Stephen L. Cropper	Director	May 30, 2019
Stephen L. Cropper		
/s/ Bryan K. Guderian	Director	May 30, 2019
Bryan K. Guderian		
/s/ James C. Kneale	Director	May 30, 2019
James C. Kneale		
/s/ John T. Raymond	Director	May 30, 2019
John T. Raymond		
/s/ L. John Schaufele IV	Director	May 30, 2019
L. John Schaufele IV		

INDEX TO FINANCIAL STATEMENTS

NGL ENERGY PARTNERS LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
NGL Energy Partners LP

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of NGL Energy Partners LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of March 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended March 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of March 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended March 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Partnership's internal control over financial reporting as of March 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated May 30, 2019 expressed an unqualified opinion.

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

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

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2010.

Tulsa, Oklahoma
May 30, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
NGL Energy Partners LP

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of NGL Energy Partners LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of March 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of March 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Partnership as of and for the year ended March 31, 2019, and our report dated May 30, 2019 expressed an unqualified opinion on those financial statements.

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

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

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

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

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
May 30, 2019

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Consolidated Balance Sheets
(in Thousands, except unit amounts)

	March 31, 2019	March 31, 2018
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 18,572	$ 22,094
Accounts receivable-trade, net of allowance for doubtful accounts of $4,366 and $4,201, respectively	1,162,919	1,026,764
Accounts receivable-affiliates	12,867	4,772
Inventories	463,143	551,303
Prepaid expenses and other current assets	155,172	128,742
Assets held for sale	—	517,604
Total current assets	1,812,673	2,251,279
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation of $420,362 and $343,345, respectively	1,844,493	1,518,607
GOODWILL	1,145,861	1,204,607
INTANGIBLE ASSETS, net of accumulated amortization of $524,257 and $433,565, respectively	938,335	913,154
INVESTMENTS IN UNCONSOLIDATED ENTITIES	1,127	17,236
LOAN RECEIVABLE-AFFILIATE	—	1,200
OTHER NONCURRENT ASSETS	160,004	245,039
Total assets	$ 5,902,493	$ 6,151,122
LIABILITIES AND EQUITY		
CURRENT LIABILITIES AND REDEEMABLE NONCONTROLLING INTEREST:		
Accounts payable-trade	$ 964,665	$ 852,839
Accounts payable-affiliates	28,469	1,254
Accrued expenses and other payables	248,450	223,504
Advance payments received from customers	8,921	8,374
Current maturities of long-term debt	648	646
Liabilities and redeemable noncontrolling interest held for sale	—	42,580
Total current liabilities and redeemable noncontrolling interest	1,251,153	1,129,197
LONG-TERM DEBT, net of debt issuance costs of $12,008 and $20,645, respectively, and current maturities	2,160,133	2,679,740
OTHER NONCURRENT LIABILITIES	63,575	173,514
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
CLASS A 10.75% CONVERTIBLE PREFERRED UNITS, 19,942,169 and 19,942,169 preferred units issued and outstanding, respectively	149,814	82,576
EQUITY:		
General partner, representing a 0.1% interest, 124,633 and 121,594 notional units, respectively	(50,603)	(50,819)
Limited partners, representing a 99.9% interest, 124,508,497 and 121,472,725 common units issued and outstanding, respectively	2,067,197	1,852,495
Class B preferred limited partners, 8,400,000 and 8,400,000 preferred units issued and outstanding, respectively	202,731	202,731
Accumulated other comprehensive loss	(255)	(1,815)
Noncontrolling interests	58,748	83,503
Total equity	2,277,818	2,086,095
Total liabilities and equity	$ 5,902,493	$ 6,151,122

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

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Consolidated Statements of Operations
(in Thousands, except unit and per unit amounts)

	Year Ended March 31,		
	2019	**2018**	**2017**
REVENUES:			
Crude Oil Logistics	$ 3,136,635	$ 2,260,075	$ 1,666,884
Water Solutions	301,686	229,139	159,601
Liquids	2,415,041	2,215,985	1,537,172
Refined Products and Renewables	18,162,183	12,200,923	9,342,702
Other	1,362	1,174	844
Total Revenues	24,016,907	16,907,296	12,707,203
COST OF SALES:			
Crude Oil Logistics	2,902,656	2,113,747	1,572,015
Water Solutions	(10,787)	19,345	4,068
Liquids	2,277,709	2,128,522	1,432,200
Refined Products and Renewables	18,113,410	12,150,497	9,219,721
Other	1,929	530	400
Total Cost of Sales	23,284,917	16,412,641	12,228,404
OPERATING COSTS AND EXPENSES:			
Operating	240,684	201,068	189,003
General and administrative	107,534	98,129	105,805
Depreciation and amortization	212,860	209,020	180,239
Loss (gain) on disposal or impairment of assets, net	34,296	(17,104)	(208,890)
Revaluation of liabilities	(5,373)	20,716	6,717
Operating Income (Loss)	141,989	(17,174)	205,925
OTHER INCOME (EXPENSE):			
Equity in earnings of unconsolidated entities	2,533	7,539	3,830
Revaluation of investments	—	—	(14,365)
Interest expense	(164,726)	(199,148)	(149,994)
(Loss) gain on early extinguishment of liabilities, net	(12,340)	(23,201)	24,727
Other (expense) income, net	(29,946)	6,953	26,612
(Loss) Income From Continuing Operations Before Income Taxes	(62,490)	(225,031)	96,735
INCOME TAX EXPENSE	(1,234)	(1,354)	(1,933)
(Loss) Income From Continuing Operations	(63,724)	(226,385)	94,802
Income From Discontinued Operations, net of Tax	403,119	156,780	49,072
Net Income (Loss)	339,395	(69,605)	143,874
LESS: NET LOSS (INCOME) ATTRIBUTABLE TO NONCONTROLLING INTERESTS	20,206	(240)	(6,832)
LESS: NET LOSS (INCOME) ATTRIBUTABLE TO REDEEMABLE NONCONTROLLING INTERESTS	446	(1,030)	—
NET INCOME (LOSS) ATTRIBUTABLE TO NGL ENERGY PARTNERS LP	$ 360,047	$ (70,875)	$ 137,042
NET (LOSS) INCOME FROM CONTINUING OPERATIONS ALLOCATED TO COMMON UNITHOLDERS (NOTE 3)	$ (155,437)	$ (286,521)	$ 57,645
NET INCOME FROM DISCONTINUED OPERATIONS ALLOCATED TO COMMON UNITHOLDERS (NOTE 3)	$ 403,161	$ 155,595	$ 49,023
NET INCOME (LOSS) ALLOCATED TO COMMON UNITHOLDERS	$ 247,724	$ (130,926)	$ 106,668
BASIC INCOME (LOSS) PER COMMON UNIT			
(Loss) Income From Continuing Operations	$ (1.26)	$ (2.37)	$ 0.53
Income From Discontinued Operations, net of Tax	$ 3.28	$ 1.29	$ 0.45
Net Income (Loss)	$ 2.01	$ (1.08)	$ 0.99
DILUTED INCOME (LOSS) PER COMMON UNIT			
(Loss) Income From Continuing Operations	$ (1.26)	$ (2.37)	$ 0.52
Income From Discontinued Operations, net of Tax	$ 3.28	$ 1.29	$ 0.44
Net Income (Loss)	$ 2.01	$ (1.08)	$ 0.95
BASIC WEIGHTED AVERAGE COMMON UNITS OUTSTANDING	123,017,064	120,991,340	108,091,486
DILUTED WEIGHTED AVERAGE COMMON UNITS OUTSTANDING	123,017,064	120,991,340	111,850,621

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

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
(in Thousands)

	Year Ended March 31,		
	2019	2018	2017
Net income (loss)	$ 339,395	$ (69,605)	$ 143,874
Other comprehensive (loss) income	(9)	13	(1,671)
Comprehensive income (loss)	$ 339,386	$ (69,592)	$ 142,203

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

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Consolidated Statements of Changes in Equity
For the Years Ended March 31, 2019, 2018, and 2017
(in Thousands, except unit amounts)

		Limited Partners						
		Class B Preferred		Common				
	General Partner	Units	Amount	Units	Amount	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
BALANCES AT MARCH 31, 2016	$(50,811)	—	$ —	104,169,573	$1,707,326	$ (157)	$ 37,707	$1,694,065
Distributions to general and common unit partners and preferred unitholders (Note 10)	(287)	—	—	—	(181,294)	—	—	(181,581)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	(3,292)	(3,292)
Contributions	49	—	—	—	(501)	—	1,173	721
Business combinations	—	—	—	218,617	3,940	—	—	3,940
Purchase of noncontrolling interest	—	—	—	—	(215)	—	(12,602)	(12,817)
Equity issued pursuant to incentive compensation plan (Note 10)	—	—	—	2,350,082	68,414	—	—	68,414
Common units issued, net of offering costs (Note 10)	288	—	—	13,441,135	286,848	—	—	287,136
Allocation of value to beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	131,534	—	—	131,534
Issuance of warrants, net of offering costs (Note 10)	—	—	—	—	48,550	—	—	48,550
Accretion of beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	(8,999)	—	—	(8,999)
Transfer of redeemable noncontrolling interest (Note 2)	—	—	—	—	—	—	(3,072)	(3,072)
Net income	232	—	—	—	136,810	—	6,832	143,874
Other comprehensive loss	—	—	—	—	—	(1,671)	—	(1,671)
BALANCES AT MARCH 31, 2017	(50,529)	—	—	120,179,407	2,192,413	(1,828)	26,746	2,166,802
Distributions to general and common unit partners and preferred unitholders (Note 10)	(323)	—	—	—	(229,469)	—	—	(229,792)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	(3,082)	(3,082)
Contributions	—	—	—	—	—	—	23	23
Sawtooth joint venture (Note 16)	—	—	—	—	(16,981)	—	76,214	59,233
Purchase of noncontrolling interest (Note 4)	—	—	—	—	(6,245)	—	(16,638)	(22,883)
Redeemable noncontrolling interest valuation adjustment (Note 2)	—	—	—	—	(5,825)	—	—	(5,825)
Repurchase of warrants (Note 10)	—	—	—	—	(10,549)	—	—	(10,549)
Equity issued pursuant to incentive compensation plan (Note 10)	28	—	—	2,260,011	34,623	—	—	34,651
Common unit repurchases and cancellations (Note 10)	—	—	—	(1,574,346)	(15,817)	—	—	(15,817)
Warrants exercised (Note 10)	—	—	—	607,653	6	—	—	6
Accretion of beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	(18,781)	—	—	(18,781)
Issuance of Class B preferred units, net of offering costs (Note 10)	—	8,400,000	202,731	—	—	—	—	202,731
Net income (loss)	5	—	—	—	(70,880)	—	240	(70,635)
Other comprehensive income	—	—	—	—	—	13	—	13
BALANCES AT MARCH 31, 2018	(50,819)	8,400,000	202,731	121,472,725	1,852,495	(1,815)	83,503	2,086,095
Distributions to general and common unit partners and preferred unitholders (Note 10)	(330)	—	—	—	(236,303)	—	—	(236,633)
Contributions	—	—	—	—	—	—	169	169
Sawtooth joint venture (Note 16)	—	—	—	—	(63)	—	(791)	(854)
Purchase of noncontrolling interest (Note 4)	—	—	—	—	(33)	—	(3,927)	(3,960)
Redeemable noncontrolling interest valuation adjustment (Note 2)	—	—	—	—	(3,349)	—	—	(3,349)
Repurchase of warrants (Note 10)	—	—	—	—	(14,988)	—	—	(14,988)
Common unit repurchases and cancellations (Note 10)	—	—	—	(26,993)	(297)	—	—	(297)
Equity issued pursuant to incentive compensation plan (Note 10)	22	—	—	2,833,968	39,712	—	—	39,734
Warrants exercised (Note 10)	—	—	—	228,797	2	—	—	2
Accretion of beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	(67,239)	—	—	(67,239)
Net income (loss)	387	—	—	—	359,660	—	(20,206)	339,841
Other comprehensive loss	—	—	—	—	—	(9)	—	(9)
Cumulative effect adjustment for adoption of ASC 606 (Note 15)	139	—	—	—	139,167	—	—	139,306
Cumulative effect adjustment for adoption of ASU 2016-01 (Note 2)	(2)	—	—	—	(1,567)	1,569	—	—
BALANCES AT MARCH 31, 2019	$(50,603)	8,400,000	$202,731	124,508,497	$2,067,197	$ (255)	$ 58,748	$2,277,818

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

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(in Thousands)

	Year Ended March 31,		
	2019	2018	2017
OPERATING ACTIVITIES:			
Net income (loss)	$ 339,395	$ (69,605)	$ 143,874
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Income from discontinued operations, net of tax	(403,119)	(156,780)	(49,072)
Depreciation and amortization, including amortization of debt issuance costs	227,694	225,738	194,829
Loss (gain) on early extinguishment or revaluation of liabilities, net	6,967	43,917	(18,010)
Gain on termination of a storage sublease agreement	—	—	(16,205)
Non-cash equity-based compensation expense	41,367	35,241	53,102
Loss (gain) on disposal or impairment of assets, net	34,296	(17,104)	(208,890)
Provision for doubtful accounts	369	590	(1,000)
Net adjustments to fair value of commodity derivatives	(33,631)	116,604	55,978
Equity in earnings of unconsolidated entities	(2,533)	(7,539)	(3,830)
Distributions of earnings from unconsolidated entities	2,206	4,632	3,564
Lower of cost or market value adjustment	50,987	399	(1,283)
Revaluation of investments	—	—	14,365
Other	(485)	(41)	(7,809)
Changes in operating assets and liabilities, exclusive of acquisitions:			
Accounts receivable-trade and affiliates	(144,209)	(272,990)	(254,124)
Inventories	52,870	(8,048)	(189,311)
Other current and noncurrent assets	44,261	(22,472)	(54,184)
Accounts payable-trade and affiliates	101,699	195,339	236,633
Other current and noncurrent liabilities	(10,620)	(14,252)	3,573
Net cash provided by (used in) operating activities-continuing operations	307,514	53,629	(97,800)
Net cash provided by operating activities-discontinued operations	29,736	84,338	72,762
Net cash provided by (used in) operating activities	337,250	137,967	(25,038)
INVESTING ACTIVITIES:			
Capital expenditures	(455,613)	(133,761)	(344,936)
Acquisitions, net of cash acquired	(316,936)	(19,897)	(41,928)
Net settlements of commodity derivatives	18,405	(100,405)	(37,086)
Proceeds from sales of assets	16,177	33,844	28,232
Proceeds from divestitures of businesses and investments, net	335,809	329,780	134,370
Transaction with Victory Propane (Note 13)	—	(6,424)	—
Investments in unconsolidated entities	(389)	(21,465)	(2,105)
Distributions of capital from unconsolidated entities	1,440	11,969	9,692
Repayments on loan for natural gas liquids facility	10,336	10,052	8,916
Loan to affiliate	(1,515)	(2,510)	(3,200)
Repayments on loan to affiliate	—	4,160	655
Payment to terminate development agreement	—	—	(16,875)
Net cash (used in) provided by investing activities-continuing operations	(392,286)	105,343	(264,265)
Net cash provided by (used in) investing activities-discontinued operations	845,759	165,239	(98,861)
Net cash provided by (used in) investing activities	453,473	270,582	(363,126)
FINANCING ACTIVITIES:			
Proceeds from borrowings under revolving credit facilities	4,098,500	2,434,500	1,700,000
Payments on revolving credit facilities	(3,897,000)	(2,279,500)	(2,733,500)
Issuance of senior unsecured notes	—	—	1,200,000
Repayment and repurchase of senior secured and senior unsecured notes	(737,058)	(486,699)	(21,193)
Payments on other long-term debt	(653)	(877)	(46,153)
Debt issuance costs	(1,383)	(2,700)	(33,558)
Contributions from general partner	—	—	49
Contributions from noncontrolling interest owners, net	169	23	672
Distributions to general and common unit partners and preferred unitholders	(236,633)	(225,067)	(181,581)
Distributions to noncontrolling interest owners	—	(3,082)	(3,292)
Proceeds from sale of preferred units, net of offering costs	—	202,731	234,975
Repurchase of warrants	(14,988)	(10,549)	—
Common unit repurchases and cancellations	(297)	(15,817)	—
Proceeds from sale of common units, net of offering costs	—	—	287,136
Payments for settlement and early extinguishment of liabilities	(4,577)	(3,408)	(28,468)

Net cash (used in) provided by financing activities-continuing operations	(793,920)	(390,445)	375,087
Net cash used in financing activities-discontinued operations	(325)	(3,836)	(3,633)
Net cash (used in) provided by financing activities	(794,245)	(394,281)	371,454
Net (decrease) increase in cash and cash equivalents	(3,522)	14,268	(16,710)
Cash and cash equivalents, beginning of period	22,094	7,826	24,536
Cash and cash equivalents, end of period	$ 18,572	$ 22,094	$ 7,826

Supplemental cash flow information:						
Cash interest paid	$	170,632	$	192,938	$	117,912
Income taxes paid (net of income tax refunds)	$	2,423	$	1,843	$	2,022
Supplemental non-cash investing and financing activities:						
Distributions declared but not paid to Class B preferred unitholders	$	4,725	$	4,725	$	—
Accrued capital expenditures	$	19,121	$	12,123	$	1,758
Value of common units issued in business combinations	$	—	$	—	$	3,940

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

Note 1—Nature of Operations and Organization

NGL Energy Partners LP ("we," "us," "our," or the "Partnership") is a Delaware limited partnership formed in September 2010. NGL Energy Holdings LLC serves as our general partner. At March 31, 2019, our operations included:

- Our Crude Oil Logistics segment purchases crude oil from producers and marketers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets.
- Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services and sells freshwater to producers for exploration and production activities.
- Our Liquids segment supplies natural gas liquids to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada using its leased underground storage and fleet of leased railcars, markets regionally through its 27 owned terminals throughout the United States, and provides terminaling and storage services at its salt dome storage facility joint venture in Utah. See Note 16 for a discussion of the joint venture of our Sawtooth Caverns, LLC ("Sawtooth") business.
- Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations , purchases refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedules them for delivery at various locations throughout the country. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties.

Recent Developments

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG ("DCC") for net proceeds of $212.4 million in cash. The Retail Propane businesses subject to this transaction consisted of our operations across the Mid-Continent and Western portions of the United States. On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior Plus Corp. ("Superior") for total consideration of $889.8 million in cash. We retained our 50% ownership interest in Victory Propane, LLC ("Victory Propane"), which we subsequently sold on August 14, 2018 (see Note 2). These transactions represent a strategic shift in our operations and will have a significant effect on our operations and financial results going forward. Accordingly, the results of operations and cash flows related to our former Retail Propane segment (including equity in earnings of Victory Propane) have been classified as discontinued operations for all periods presented and prior periods have been retrospectively adjusted in the consolidated statements of operations and consolidated statements of cash flows. In addition, the assets and liabilities related to our former Retail Propane segment have been classified as held for sale within our March 31, 2018 consolidated balance sheet. See Note 17 for a further discussion of the transaction.

Note 2—Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). The accompanying consolidated financial statements include our accounts and those of our controlled subsidiaries. Intercompany transactions and account balances have been eliminated in consolidation. Investments we do not control, but can exercise significant influence over, are accounted for using the equity method of accounting. We also own an undivided interest in a crude oil pipeline, and include our proportionate share of assets, liabilities, and expenses related to this pipeline in our consolidated financial statements.

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the amount of assets and liabilities reported at the date of the consolidated financial statements and the amount of revenues and expenses reported during the periods presented.

Critical estimates we make in the preparation of our consolidated financial statements include, among others, determining the fair value of assets and liabilities acquired in acquisitions, the fair value of derivative instruments, the collectibility of accounts receivable, the recoverability of inventories, useful lives and recoverability of property, plant and equipment and amortizable intangible assets, the impairment of long-lived assets and goodwill, the fair value of asset retirement obligations, the value of equity-based compensation, accruals for environmental matters and estimating certain revenues. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Fair value is based upon assumptions that market participants would use when pricing an asset or liability. We use the following fair value hierarchy, which prioritizes valuation technique inputs used to measure fair value into three broad levels:

- Level 1: Quoted prices in active markets for identical assets and liabilities that we have the ability to access at the measurement date.
- Level 2: Inputs (other than quoted prices included within Level 1) that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability, and (iv) inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter commodity price swap and option contracts and forward commodity contracts. We determine the fair value of all of our derivative financial instruments utilizing pricing models for similar instruments. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.
- Level 3: Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable inputs (Level 3). In some cases, the inputs used to measure fair value might fall into different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to a fair value measurement requires judgment, considering factors specific to the asset or liability.

Derivative Financial Instruments

We record all derivative financial instrument contracts at fair value in our consolidated balance sheets except for certain physical contracts that qualify for the normal purchase and normal sale election . Under this accounting policy election, we do not record the physical contracts at fair value at each balance sheet date; instead, we record the purchase or sale at the contracted value once the delivery occurs.

We have not designated any financial instruments as hedges for accounting purposes. All changes in the fair value of our physical contracts that do not qualify as normal purchases and normal sales and settlements (whether cash transactions or non-cash mark-to-market adjustments) are reported either within revenue (for sales contracts) or cost of sales (for purchase contracts) in our consolidated statements of operations, regardless of whether the contract is physically or financially settled.

We utilize various commodity derivative financial instrument contracts to attempt to reduce our exposure to price fluctuations. We do not enter into such contracts for trading purposes. Changes in assets and liabilities from commodity derivative financial instruments result primarily from changes in market prices, newly originated transactions, and the timing of settlements and are reported within cost of sales on the consolidated statements of operations, along with related settlements. We attempt to balance our contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. However, net unbalanced positions can exist or are established based on our assessment of anticipated market movements. Inherent in the resulting contractual portfolio are certain business risks, including commodity price risk and credit risk. Commodity price risk is the risk that the market value of crude oil, natural gas liquids, or refined and renewables products will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. Procedures and limits for managing commodity price risks and credit risks are specified in our market risk policy and credit policy, respectively. Open commodity positions and market price changes are monitored daily and are reported to senior management and to marketing operations personnel. Credit risk is monitored daily and exposure is minimized through customer deposits, restrictions on product liftings, letters of credit, and entering into master netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions.

Cost of Sales

We include all costs we incur to acquire products, including the costs of purchasing, terminaling, and transporting inventory, prior to delivery to our customers, in cost of sales. Cost of sales excludes depreciation of our property, plant and equipment.

Depreciation and Amortization

Depreciation and amortization in our consolidated statements of operations includes all depreciation of our property, plant and equipment and amortization of intangible assets other than debt issuance costs, for which the amortization is recorded to interest expense, and certain contract-based intangible assets, for which the amortization is recorded to cost of sales.

Income Taxes

We qualify as a partnership for income tax purposes. As such, we generally do not pay United States federal income tax. Rather, each owner reports his or her share of our income or loss on his or her individual tax return. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined, as we do not have access to information regarding each partner’s basis in the Partnership.

We have certain taxable corporate subsidiaries in the United States and Canada, and our operations in Texas are subject to a state franchise tax that is calculated based on revenues net of cost of sales. Our fiscal years 2015 to 2018 generally remain subject to examination by federal, state, and Canadian tax authorities. We utilize the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. Changes in tax rates are recognized in income in the period that includes the enactment date.

A publicly traded partnership is required to generate at least 90% of its gross income (as defined for federal income tax purposes) from certain qualifying sources. Income generated by our taxable corporate subsidiaries is excluded from this qualifying income calculation. Although we routinely generate income outside of our corporate subsidiaries that is non-qualifying, we believe that at least 90% of our gross income has been qualifying income for each of the calendar years since our IPO.

During the year ended March 31, 2019, we recognized a deferred tax liability of $16.3 million as a result of acquiring a corporation in connection with one of our acquisitions (see Note 4). The deferred tax liability is the tax effected cumulative temporary difference between the GAAP basis and tax basis of the acquired assets within the corporation. For GAAP purposes, certain of the acquired assets will be depreciated and amortized over time which will lower the GAAP basis. The deferred tax benefit recorded for the year ended March 31, 2019 is $1.5 million with an effective tax rate of 31%. The deferred tax liability is $14.8 million at March 31, 2019 and is included within other noncurrent liabilities in our consolidated balance sheet.

We evaluate uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, we determine whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. We had no material uncertain tax positions that required recognition in our consolidated financial statements at March 31, 2019 or 2018.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand and time deposits, and funds invested in highly liquid instruments with maturities of three months or less at the date of purchase. At times, certain account balances may exceed federally insured limits.

Accounts Receivable and Concentration of Credit Risk

We operate in the United States and Canada. We grant unsecured credit to customers under normal industry standards and terms, and have established policies and procedures that allow for an evaluation of each customer's creditworthiness as well as general economic conditions. The allowance for doubtful accounts is based on our assessment of the collectibility of customer accounts, which assessment considers the overall creditworthiness of customers and any specific disputes. Accounts receivable are considered past due or delinquent based on contractual terms. We write off accounts receivable against the allowance for doubtful accounts when collection efforts have been exhausted.

We execute netting agreements with certain customers to mitigate our credit risk. Receivables and payables are reflected at a net balance to the extent a netting agreement is in place and we intend to settle on a net basis.

Our accounts receivable consist of the following at the dates indicated:

	March 31, 2019			March 31, 2018		
Segment	**Gross Receivable**	**Allowance for Doubtful Accounts**	**Net**	**Gross Receivable**	**Allowance for Doubtful Accounts**	**Net**
	(in thousands)					
Crude Oil Logistics	$ 514,243	$ (15)	$ 514,228	$ 404,865	$ —	$ 404,865
Water Solutions	57,526	(3,157)	54,369	59,958	(2,952)	57,006
Liquids	134,050	(177)	133,873	131,006	(20)	130,986
Refined Products and Renewables	461,050	(1,017)	460,033	435,136	(1,229)	433,907
Corporate and Other	416	—	416	—	—	—
Total	$ 1,167,285	$ (4,366)	$ 1,162,919	$ 1,030,965	$ (4,201)	$ 1,026,764

Changes in the allowance for doubtful accounts are as follows for the periods indicated:

	Year Ended March 31,		
	2019	**2018**	**2017**
	(in thousands)		
Allowance for doubtful accounts, beginning of period	$ (4,201)	$ (3,954)	$ (5,963)
Provision for doubtful accounts	(369)	(590)	1,000
Write off of uncollectible accounts	204	343	1,009
Allowance for doubtful accounts, end of period	$ (4,366)	$ (4,201)	$ (3,954)

Amounts in the tables above do not include accounts receivable or allowance for doubtful accounts related to our former Retail Propane segment, as these amounts have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet and the activity has been included within discontinued operations within our consolidated statements of operations (see Note 17).

We did not have any customers that represented over 10% of consolidated revenues for fiscal years 2019, 2018 and 2017.

Inventories

Our inventories are valued at the lower of cost or net realizable value, with cost determined using either the weighted-average cost or the first in, first out (FIFO) methods, including the cost of transportation and storage, and with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. In performing this analysis, we consider fixed-price forward commitments.

Inventories consist of the following at the dates indicated:

	March 31,	
	2019	2018
	(in thousands)	
Crude oil	$ 51,359	$ 77,351
Natural gas liquids:		
Propane	33,478	38,910
Butane	15,294	12,613
Other	7,482	6,515
Refined products:		
Gasoline	189,802	253,286
Diesel	103,935	113,939
Renewables:		
Ethanol	51,542	38,093
Biodiesel	10,251	10,596
Total	$ 463,143	$ 551,303

Amounts in the table above do not include inventory related to our former Retail Propane segment, as these amounts have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

Investments in Unconsolidated Entities

Investments we do not control, but can exercise significant influence over, are accounted for using the equity method of accounting. Investments in partnerships and limited liability companies, unless our investment is considered to be minor, and investments in unincorporated joint ventures are also accounted for using the equity method of accounting. Under the equity method, we do not report the individual assets and liabilities of these entities on our consolidated balance sheets; instead, our ownership interests are reported within investments in unconsolidated entities on our consolidated balance sheets. Under the equity method, the investment is recorded at acquisition cost, increased by our proportionate share of any earnings and additional capital contributions and decreased by our proportionate share of any losses, distributions paid, and amortization of any excess investment. Excess investment is the amount by which our total investment exceeds our proportionate share of the net assets of the investee. We consider distributions received from unconsolidated entities which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and are classified as operating activities in our consolidated statements of cash flows. We consider distributions received from unconsolidated entities in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment and are classified as investing activities in our consolidated statements of cash flows.

Our investments in unconsolidated entities consist of the following at the dates indicated:

Entity	Segment	Ownership Interest (1)	Date Acquired or Formed	March 31, 2019	March 31, 2018
				(in thousands)	
Water services company (2)	Water Solutions	50%	August 2018	$ 920	$ —
Natural gas liquids terminal company (3)	Liquids	50%	March 2019	207	—
Water treatment and disposal facility (4)	Water Solutions	—%	August 2015	—	2,094
E Energy Adams, LLC (5)	Refined Products and Renewables	—%	December 2013	—	15,142
Victory Propane (6)	Corporate and Other	—%	April 2015	—	—
Total				$ 1,127	$ 17,236

(1) Ownership interest percentages are atMarch 31, 2019.

(2) This is an investment in an unincorporated joint venture that we acquired as part of an acquisition in August 2018. See Note 4 for a further discussion.

(3) This is an investment in an unincorporated joint venture that we acquired as part of an acquisition in March 2019. See Note 4 for a further discussion.

(4) This is an investment in an unincorporated joint venture. On February 28, 2019, we sold this investment as part of the sale of our South Pecos water disposal business. See Note 16 for a further discussion.

(5) On May 3, 2018, we sold our previously held 20% interest in E Energy Adams, LLC for net proceeds of $18.6 million and recorded a gain on disposal of $3.0 million during the year ended March 31, 2019 within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations.

(6) On August 14, 2018, we sold our previously held 50% interest in Victory Propane. See Note 13 for a further discussion.

Combined summarized financial information for all of our unconsolidated entities is as follows for the dates and periods indicated:

Balance sheets:

	March 31,	
	2019	2018
	(in thousands)	
Current assets	$ 1,328	$ 24,431
Noncurrent assets	$ 519	$ 99,164
Current liabilities	$ 178	$ 16,787
Noncurrent liabilities	$ —	$ 10,620

Statements of operations:

	March 31,		
	2019	2018	2017
	(in thousands)		
Revenues	$ 21,036	$ 182,820	$ 180,632
Cost of sales	$ 9,919	$ 114,890	$ 114,316
Net income	$ 5,506	$ 26,438	$ 19,462

At March 31, 2019, cumulative equity earnings and cumulative distributions of our unconsolidated entities since they were acquired were $1.9 million and $3.0 million, respectively.

Variable Interest Entity

Victory Propane was formed as a joint venture in April 2015 by us and an unrelated third party. The business purpose of Victory Propane is to acquire and/or develop retail propane operations in a defined geographic area. In conjunction with the formation of Victory Propane, we agreed to provide Victory Propane a revolving line of credit of $5.0 million and have concluded that Victory Propane is a variable interest entity because the equity of Victory Propane is not sufficient to fund its activities without additional subordinated financial support. On August 14, 2018, we sold our interest in Victory Propane. Our equity in earnings in Victory Propane has been classified within discontinued operations, as discussed further in Note 1 and Note 17.

Other Noncurrent Assets

Other noncurrent assets consist of the following at the dates indicated:

	March 31,	
	2019	2018
	(in thousands)	
Loan receivable (1)	$ 19,474	$ 29,463
Line fill (2)	33,437	34,897
Tank bottoms (3)	44,148	42,044
Minimum shipping fees - pipeline commitments (4)	23,494	88,757
Other	39,451	49,878
Total	$ 160,004	$ 245,039

(1) Represents the noncurrent portion of a loan receivable associated with our financing of the construction of a natural gas liquids facility that is utilized by a third party and the noncurrent portion of a loan receivable with Victory Propane (see Note 13).

(2) Represents minimum volumes of product we are required to leave on certain third-party owned pipelines under long-term shipment commitments. At March 31, 2019, line fill consisted of 335,069 barrels of crude oil and 262,000 barrels of propane. At March 31, 2018, line fill consisted of 360,425 barrels of crude oil and 262,000 barrels of propane. Line fill held in pipelines we own is included within property, plant and equipment (see Note 5).

(3) Tank bottoms, which are product volumes required for the operation of storage tanks, are recorded at historical cost. We recover tank bottoms when the storage tanks are removed from service. At March 31, 2019 and 2018, tank bottoms held in third party terminals consisted of 389,737 barrels and 366,212 barrels of refined products, respectively. Tank bottoms held in terminals we own are included within property, plant and equipment (see Note 5).

(4) Represents the minimum shipping fees paid in excess of volumes shipped, or deficiency credits, for two contracts with crude oil pipeline operators. This amount can be recovered when volumes shipped exceed the minimum monthly volume commitment (see Note 9). During the three months ended June 30, 2018, we entered into a definitive agreement, as described further in Note 13, in which we agreed to provide the benefit of our deficiency credit under one of these contracts. As a result of providing this benefit to the third party, we wrote off $67.7 million of these deficiency credits and recorded a loss within loss (gain) on disposal or impairment of assets, net Under the remaining other contract for which we have the future benefit, we currently have 13 months in which to ship the excess volumes.

Amounts in the table above do not include other noncurrent assets related to our former Retail Propane segment, as these amounts have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

Accrued Expenses and Other Payables

Accrued expenses and other payables consist of the following at the dates indicated:

	March 31,	
	2019	2018
	(in thousands)	
Accrued compensation and benefits	$ 19,558	$ 18,033
Excise and other tax liabilities	40,339	40,829
Derivative liabilities	100,372	51,039
Accrued interest	24,882	39,947
Product exchange liabilities	21,081	11,842
Gavilon legal matter settlement (Note 9)	12,500	—
Deferred gain on sale of general partner interest in TLP (1)	—	30,113
Other	29,718	31,701
Total	$ 248,450	$ 223,504

(1) See Note 15 for a discussion of the accounting for the deferred gain upon adoption of ASC 606.

Amounts in the table above do not include accrued expenses and other payables related to our former Retail Propane segment, as these amounts have been classified as liabilities held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

Property, Plant and Equipment

We record property, plant and equipment at cost, less accumulated depreciation. Acquisitions and improvements are capitalized, and maintenance and repairs are expensed as incurred. As we dispose of assets, we remove the cost and related accumulated depreciation from the accounts, and any resulting gain or loss is included within loss (gain) on disposal or impairment of assets, net . We compute depreciation expense of our property, plant and equipment using the straight-line method over the estimated useful lives of the assets (see Note 5).

Intangible Assets

Our intangible assets include contracts and arrangements acquired in business combinations, including customer relationships, customer commitments, pipeline capacity rights, rights-of-way and easements, water rights, executory contracts and other agreements, covenants not to compete, and trade names. In addition, we capitalize certain debt issuance costs associated with the revolving credit facilities. We amortize the majority of our intangible assets on a straight-line basis over the estimated useful lives of the assets (see Note 7). We amortize debt issuance costs over the terms of the related debt using a method that approximates the effective interest method.

Impairment of Long-Lived Assets

We evaluate the carrying value of our long-lived assets (property, plant and equipment and amortizable intangible assets) for potential impairment when events and circumstances warrant such a review. A long-lived asset group is considered impaired when the anticipated undiscounted future cash flows from the use and eventual disposition of the asset group is less than its carrying value. In that event, we recognize a loss equal to the amount by which the carrying value exceeds the fair value of the asset group. When we cease to use an acquired trade name, we test the trade name for impairment using the relief from royalty method and we begin amortizing the trade name over its estimated useful life as a defensive asset. See Note 5 and Note 7 for a further discussion of long-lived asset impairments recognized in the consolidated statements of operations.

We evaluate our equity method investments for impairment when we believe the current fair value may be less than the carrying amount and record an impairment if we believe the decline in value is other than temporary.

Goodwill

Goodwill represents the excess of the consideration paid for the acquired businesses over the fair value of the individual assets acquired, net of liabilities assumed. Business combinations are accounted for using the “acquisition method” (see Note 4). We expect that all of our goodwill at March 31, 2019 is deductible for federal income tax purposes.

Goodwill and indefinite-lived intangible assets are not amortized, but instead are evaluated for impairment at least annually. We perform our annual assessment of impairment during the fourth quarter of our fiscal year, and more frequently if circumstances warrant.

To perform this assessment, we first consider qualitative factors to determine whether it is more likely than not that the fair value of each reporting unit exceeds its carrying amount. If we conclude that it is more likely than not that the fair value of a reporting unit does not exceed its carrying amount, we calculate the fair value for the reporting unit and compare the amount to its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered impaired. If the carrying amount of a reporting unit exceeds its fair value, goodwill is considered to be impaired and the goodwill balance is reduced by the difference between the fair value and carrying amount of the reporting unit.

Estimates and assumptions used to perform the impairment evaluation are inherently uncertain and can significantly affect the outcome of the analysis. The estimates and assumptions we used in the annual goodwill impairment assessment included market participant considerations and future forecasted operating results. Changes in operating results and other assumptions could materially affect these estimates. See Note 6 for a further discussion and analysis of our goodwill impairment assessment.

Product Exchanges

Quantities of products receivable or returnable under exchange agreements are reported within prepaid expenses and other current assets and within accrued expenses and other payables in our consolidated balance sheets. We estimate the value of product exchange assets and liabilities based on the weighted-average cost basis of the inventory we have delivered or will deliver on the exchange, plus or minus location differentials. Product exchanges related to our former Retail Propane segment have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

Noncontrolling Interests

Noncontrolling interests represent the portion of certain consolidated subsidiaries that are owned by third parties. Amounts are adjusted by the noncontrolling interest holder's proportionate share of the subsidiaries' earnings or losses each period and any distributions that are paid. Noncontrolling interests are reported as a component of equity, unless the noncontrolling interest is considered redeemable, in which case the noncontrolling interest is recorded between liabilities and equity (mezzanine or temporary equity) in our consolidated balance sheet. The redeemable noncontrolling interest is adjusted at each balance sheet date to its maximum redemption value if the amount is greater than the carrying value. The redeemable noncontrolling interest is included in liabilities and redeemable noncontrolling interest held for sale in our consolidated balance sheets (see Note 17). The following table summarizes changes in our redeemable noncontrolling interest in our consolidated balance sheets (in thousands):

Balance at March 31, 2017	$	3,072
Net income attributable to redeemable noncontrolling interest		1,030
Redeemable noncontrolling interest valuation adjustment		5,825
Balance at March 31, 2018		9,927
Net loss attributable to redeemable noncontrolling interest		(446)
Redeemable noncontrolling interest valuation adjustment		3,349
Disposal of redeemable noncontrolling interest		(12,830)
Balance at March 31, 2019	$	—

Acquisitions

To determine if a transaction should be accounted for as a business combination or an acquisition of assets, we first calculate the relative fair values of the assets acquired. If substantially all of the relative fair value is concentrated in a single asset or group of similar assets, or if not but the transaction does not include a significant process (does not meet the definition of a business), we record the transaction as an acquisition of assets. For acquisitions of assets, the purchase price is allocated based on the relative fair values. For an acquisition of assets, goodwill is not recorded. All other transactions are recorded as business combinations. We record the assets acquired and liabilities assumed in a business combination at their acquisition date fair values. For a business combination, the excess of the purchase price over the net fair value of acquired assets and assumed liabilities is recorded as goodwill, which is not amortized but instead is evaluated for impairment at least annually (as described above).

Pursuant to GAAP, an entity is allowed a reasonable period of time (not to exceed one year) to obtain the information necessary to identify and measure the fair value of the assets acquired and liabilities assumed in a business combination. As discussed in Note 4, certain of our acquisitions are still within this measurement period, and as a result, the acquisition date fair values we have recorded for the assets acquired and liabilities assumed are subject to change.

Recent Accounting Pronouncements

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-13, "Financial Instruments-Credit Losses." The ASU requires a financial asset (or a group of financial assets) measured at amortized cost to be presented at the net amount expected to be collected, which would include accounts receivable. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. The ASU is effective for the Partnership beginning April 1, 2020, and requires a modified retrospective method of adoption, although early adoption is permitted. We are currently in the process of assessing the impact of this ASU on our consolidated financial statements.

In February 2016, the FASB issued ASC 842, "Leases." This will replace previous lease accounting guidance in GAAP. The new guidance requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. It also retains a distinction between finance leases and operating leases. This guidance is effective for the Partnership beginning April 1, 2019. We evaluated our current leases and other contracts that may be considered leases under the new standard and the impact on our internal controls, accounting policies and financial statements and disclosures. Our evaluation process includes compiling a database of our leases, implementing accounting software to assist with compliance and developing internal controls to ensure completeness and accuracy of our leases meeting the scope of ASC 842. Based on our current population of leases, we expect the impact of ASC 842 to increase our assets and liabilities by between $533 million and $563 million due to the recognition of right-of-use assets and lease liabilities. We elected the following transitional practical expedients, which will allow us to not evaluate land easements prior to April 1, 2019: use hindsight in determining the lease term; to not reassess whether current or expired contracts contain leases; to not reassess the lease classification for any expired or existing leases; and to not reassess initial costs. We also expect to elect the optional transition method to record the adoption impact through a cumulative effect adjustment to equity.

On April 1, 2018, we adopted ASC 606, "Revenue from Contracts with Customers," using a modified retrospective approach of adoption. ASC 606 supersedes previous revenue recognition requirements in Topic 605, "Revenue Recognition," and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. To achieve this core principle, more judgment and estimates are required within the revenue recognition process than required under Topic 605. In addition, ASC 606 requires significantly expanded disclosures related to the nature, timing, amount and uncertainty of revenue and cash flows arising from contracts with customers. See Note 15 for a further discussion of the impact of adoption of ASC 606 on our consolidated financial statements and our revenue recognition policies.

On April 1, 2018, we adopted ASU No. 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities." One of the provisions of ASU No. 2016-01 was to supersede the guidance to classify equity securities with readily determinable fair value into different categories (that is, trading or available-for-sale) and require equity securities to be measured at fair value with changes in fair value recognized through net income. As a result of the adoption, we recorded a cumulative effect adjustment of $1.6 million, moving the unrealized loss from accumulated other comprehensive income to limited partners' equity.

Note 3—Income (Loss) Per Common Unit

The following table presents our calculation of basic and diluted weighted average common units outstanding for the periods indicated:

	Year Ended March 31,		
	2019	**2018**	**2017**
Weighted average common units outstanding during the period:			
Common units - Basic	123,017,064	120,991,340	108,091,486
Effect of Dilutive Securities:			
Performance awards	—	—	173,087
Warrants	—	—	3,586,048
Common units - Diluted	123,017,064	120,991,340	111,850,621

For the year ended March 31, 2019, the Service Awards (as defined herein), warrants and the Class A Preferred Units (as defined herein) were considered antidilutive. Due to the termination of the Performance Award plan (see Note 10), there were no outstanding Performance Awards (as defined herein) as of March 31, 2019. For the year ended March 31, 2018, the Service Awards, Performance Awards, warrants and Class A Preferred Units were considered antidilutive. For the year ended March 31, 2017, the Service Awards and Class A Preferred Units were considered antidilutive.

Our income (loss) per common unit is as follows for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands, except unit and per unit amounts)		
(Loss) income from continuing operations	$ (63,724)	$ (226,385)	$ 94,802
Less: Continuing operations loss (income) attributable to noncontrolling interests	20,206	(240)	(6,832)
Net (loss) income from continuing operations attributable to NGL Energy Partners LP	(43,518)	(226,625)	87,970
Less: Distributions to preferred unitholders (1)	(111,936)	(59,697)	(30,142)
Less: Continuing operations net loss (income) allocated to general partner (2)	17	150	(183)
Less: Repurchase of warrants (3)	—	(349)	—
Net (loss) income from continuing operations allocated to common unitholders	$ (155,437)	$ (286,521)	$ 57,645
Income from discontinued operations, net of tax	$ 403,119	$ 156,780	$ 49,072
Less: Discontinued operations loss (income) attributable to redeemable noncontrolling interests	446	(1,030)	—
Less: Discontinued operations income allocated to general partner (2)	(404)	(155)	(49)
Net income from discontinued operations allocated to common unitholders	$ 403,161	$ 155,595	$ 49,023
Net income (loss) allocated to common unitholders	$ 247,724	$ (130,926)	$ 106,668
Basic income (loss) per common unit			
(Loss) income from continuing operations	$ (1.26)	$ (2.37)	$ 0.53
Income from discontinued operations, net of tax	$ 3.28	$ 1.29	$ 0.45
Net income (loss)	$ 2.01	$ (1.08)	$ 0.99
Diluted income (loss) per common unit			
(Loss) income from continuing operations	$ (1.26)	$ (2.37)	$ 0.52
Income from discontinued operations, net of tax	$ 3.28	$ 1.29	$ 0.44
Net income (loss)	$ 2.01	$ (1.08)	$ 0.95
Basic weighted average common units outstanding	123,017,064	120,991,340	108,091,486
Diluted weighted average common units outstanding	123,017,064	120,991,340	111,850,621

(1) This amount includes the distribution to preferred unitholders as well as the accretion for the beneficial conversion, as discussed further in Note 10.

(2) Net (income) loss allocated to the general partner includes distributions to which it is entitled as the holder of incentive distribution rights.

(3) This amount represents the excess of the repurchase price over the fair value of the warrants, as discussed further in Note 10.

Note 4—Acquisitions

The following summarizes our acquisitions during the year ended March 31, 2019:

Water Pipeline Company

On April 24, 2018, we acquired the remaining 18.375% interest in NGL Water Pipelines, LLC operating in the Delaware Basin portion of the Permian Basin in West Texas for total consideration of approximately $4.0 million. The acquisition of the remaining interest was accounted for as an equity transaction, no gain or loss was recorded, and the carrying value of the noncontrolling interest was adjusted to reflect the change in ownership interest of the subsidiary. As of the date of the transaction, the 18.375% interest had a carrying value of $3.9 million.

Saltwater Water Solutions Facilities

During the year ended March 31, 2019, we acquired six saltwater disposal facilities (including 15 saltwater disposal wells) for total consideration of approximately $116.1 million.

As part of these acquisitions, we recorded customer relationship, favorable contract and non-compete agreement intangible assets whereby we estimated the value of these intangible assets using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

The agreements for these acquisitions contemplate post-closing payments for certain working capital items. We are accounting for these transactions as business combinations. The following table summarizes the transaction close date preliminary estimates of the fair values for the assets acquired and liabilities assumed (in thousands):

Property, plant and equipment	$	36,590
Goodwill		50,619
Intangible assets		29,287
Current liabilities		(10)
Other noncurrent liabilities		(410)
Fair value of net assets acquired	$	116,076

As of March 31, 2019, the allocation of the purchase price is considered preliminary as we are continuing to gather additional information to finalize the fair values of the property, plant and equipment and intangible assets.

Goodwill represents the excess of the consideration paid for the acquired businesses over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill represents a premium paid to expand the number of our disposal sites in an oilfield production basin currently serviced by us, thereby enhancing our competitive position as a provider of disposal services in this oilfield production basin. We expect that all of the goodwill will be deductible for federal income tax purposes.

The operations of these water solutions facilities have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2019 includes revenues of $12.6 million and operating income of $4.9 million that were generated by the operations of these water solutions facilities. We incurred $0.2 million of transaction costs related to these acquisitions during the year ended March 31, 2019. These amounts are recorded within general and administrative expenses in our consolidated statement of operations.

During the year ended March 31, 2019, we also acquired seven saltwater disposal wells for total consideration of $35.2 million, which we are accounting for as acquisitions of assets. The consideration paid for this transaction was allocated primarily to property, plant and equipment.

Freshwater Water Solutions Facilities

During the year ended March 31, 2019, we acquired a ranch and four freshwater facilities (including 27 freshwater wells) and a right-of-way that can be used for pipelines for total consideration of approximately $77.2 million.

As part of these acquisitions, we recorded water rights, customer relationship, favorable contract and non-compete agreement intangible assets, whereby we estimated the value of these intangible assets using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

A book/tax difference was created as part of one of these acquisitions and as a result, we have recorded a preliminary noncurrent deferred tax liability of $16.3 million (see Note 2 for a further discussion).

We recorded contingent consideration liabilities within accrued expenses and other payables and other noncurrent liabilities in our consolidated balance sheet related to future royalty payments due to the seller. We estimated the contingent consideration for one liability based on the contracted royalty rate, which is a flat rate per barrel, multiplied by the expected volumes of freshwater sold. We estimated the contingent consideration for the other liability based on the contracted royalty rate, which is a flat rate per barrel, multiplied by the expected third party volumes to be transported on the pipeline for the expected useful life of the rights-of-way. These amounts were then discounted to present value using our weighted average cost of capital plus a premium representative of the uncertainty associated with the expected volumes. As of the acquisition date, we recorded a contingent liability of $2.7 million.

We assumed land leases with a royalty component as part of the acquisition of certain of these facilities. The acquisition method of accounting requires that executory contracts with unfavorable terms relative to market conditions at the acquisition date be recorded as liabilities in the acquisition accounting. We recorded a liability within other noncurrent liabilities of $0.5 million related to these leases due to the royalty terms being deemed unfavorable. We will amortize this liability based on the volumes processed by the facilities.

The agreements for these acquisitions contemplate post-closing payments for certain working capital items. We are accounting for these transactions as business combinations. The following table summarizes the transaction close date preliminary estimates of the fair values for the assets acquired and liabilities assumed (in thousands):

Property, plant and equipment	$	7,123
Goodwill		23,570
Intangible assets		64,015
Investments in unconsolidated entities		2,060
Current liabilities		(276)
Other noncurrent liabilities		(19,288)
Fair value of net assets acquired	$	77,204

As of March 31, 2019, the allocation of the purchase price is considered preliminary as we are continuing to gather additional information to finalize the fair values of land, other property, plant and equipment, intangible assets, including customer relationships, and the investment in the unconsolidated entity. We are also engaging a third party valuation firm to assist us in this effort. The noncurrent deferred tax liability is also considered preliminary and will be finalized once the fair value of the assets acquired has been finalized.

Goodwill represents the excess of the consideration paid for the acquired businesses over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill represents a premium paid to expand our service offerings in an oilfield production basin currently serviced by us, thereby enhancing our competitive position as a provider of disposal and other services in this oilfield production basin. We expect that all of the goodwill will be deductible for federal income tax purposes.

The operations of these water solutions facilities have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2019 includes revenues of $2.0 million and an operating loss of $1.1 million that were generated by the operations of these water solutions facilities. We incurred $3.7 million of transaction costs related to these acquisitions during the year ended March 31, 2019. These amounts are recorded within general and administrative expenses in our consolidated statement of operations.

During the year ended March 31, 2019, we also acquired an additional ranch (including 18 freshwater wells) for total consideration of $28.4 million, which we are accounting for as an acquisition of assets. The consideration paid for this transaction was allocated to land and intangible assets.

Natural Gas Liquids Terminal Business

In March 2019, we completed the acquisition of the natural gas liquids terminal business of DCP Midstream, LP. The acquisition consisted of five propane rail terminals, located in the Eastern United States, a 50% ownership interest in an additional rail terminal, located in the state of Maine, and an import/export terminal located in Chesapeake, Virginia for total consideration of approximately $103.4 million. The import/export terminal has the capability to load and unload ships ranging in size from handy-sized vessels up to very large gas carriers. These terminals complement our existing natural gas liquids portfolio and also create additional opportunities for new and existing customers to supply their business.

As part of this acquisition, we recorded a customer relationship intangible asset whereby we estimated the value of this intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

The agreement for this acquisition contemplates post-closing payments for certain working capital items. We are accounting for this transaction as a business combination. The following table summarizes the transaction close date preliminary estimates of the fair values for the assets acquired and liabilities assumed (in thousands):

Inventories	$	15,370
Other current assets		667
Property, plant and equipment		42,413
Goodwill		20,472
Intangible assets		26,900
Investments in unconsolidated entities		204
Current liabilities		(2,128)
Other noncurrent liabilities		(524)
Fair value of net assets acquired	$	103,374

As of March 31, 2019, the allocation of the purchase price is considered preliminary as we are continuing to gather additional information to finalize the fair values of the property, plant and equipment, intangible assets and the investment in the unconsolidated entity.

Goodwill represents the excess of the consideration paid for the acquired businesses over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill represents a premium paid to expand the number of our natural gas liquids terminals in an area currently serviced by us, thereby enhancing our competitive position as a provider of terminaling services in this area. We expect that all of the goodwill will be deductible for federal income tax purposes.

The operations of these natural gas liquids terminals have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2019 includes revenues of $22.7 million and operating income of $2.4 million that were generated by the operations of these natural gas liquids terminals. We incurred $0.5 million of transaction costs related to this acquisition during the year ended March 31, 2019. These amounts are recorded within general and administrative expenses in our consolidated statement of operations.

Refined Products Terminals

In January 2019, we completed the acquisition of two refined products terminals located in Georgia for total consideration of approximately $16.3 million.

As part of this acquisition, we recorded a customer relationship intangible asset whereby we estimated the value of this intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

The agreement for this acquisition contemplates post-closing payments for certain working capital items. We are accounting for this transaction as a business combination. The following table summarizes the transaction close date preliminary estimates of the fair values for the assets acquired and liabilities assumed (in thousands):

Inventories	$	327
Other current assets		85
Property, plant and equipment		9,986
Goodwill		1,328
Intangible assets		4,600
Current liabilities		(4)
Fair value of net assets acquired	$	16,322

As of March 31, 2019, the allocation of the purchase price is considered preliminary as we are continuing to gather additional information to finalize the fair values of the property, plant and equipment and intangible assets.

Goodwill represents the excess of the consideration paid for the acquired businesses over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill represents a premium paid to expand the number of our refined products terminals in an area currently serviced by us, thereby enhancing our competitive position as a provider of terminaling services in this area. We expect that all of the goodwill will be deductible for federal income tax purposes.

The operations of these refined products terminals have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2019 includes revenues of $0.3 million and an operating loss of $0.1 million that were generated by the operations of these refined products terminals. We incurred $0.1 million of transaction costs related to this acquisition during the year ended March 31, 2019. These amounts are recorded within general and administrative expenses in our consolidated statement of operations.

Retail Propane Businesses

During the three months ended June 30, 2018, we acquired three retail propane businesses for total consideration of approximately $19.1 million. We accounted for these transactions as business combinations.

On July 9, 2018, and in conjunction with the sale of the Retail Propane segment (see Note 1), we acquired the remaining 40% interest in Atlantic Propane, LLC , which was part of our Retail Propane segment, for total consideration of approximately $12.8 million. The acquisition of the remaining interest was accounted for as an equity transaction, no gain or loss was recorded, and the carrying value of the noncontrolling interest was adjusted to reflect the change in ownership interest of the subsidiary. Atlantic Propane, LLC was included in the sale to Superior (see Note 1).

The assets and liabilities of these retail propane transactions were included in the sale of virtually all of our remaining Retail Propane segment on July 10, 2018 and the operations have been classified as discontinued (see Note 17).

The following summarizes the status of the preliminary purchase price allocation of acquisitions prior to April 1, 2018:

Retail Propane Businesses

During the three months ended June 30, 2018, we completed the acquisition accounting for the remaining four retail propane businesses, which were part of the sale of virtually all of our Retail Propane segment (see Note 17). The assets and liabilities are included in current assets and current liabilities held for sale in our March 31, 2018 consolidated balance sheet (see Note 17). There were no material adjustments to the fair value of assets acquired and liabilities assumed during the three months ended June 30, 2018.

Note 5—Property, Plant and Equipment

Our property, plant and equipment consists of the following at the dates indicated:

Description	Estimated Useful Lives	March 31, 2019	March 31, 2018
	(in years)	(in thousands)	
Natural gas liquids terminal and storage assets	2 - 30	$ 280,106	$ 238,487
Pipeline and related facilities	30 - 40	243,799	243,616
Refined products terminal assets and equipment	15 - 25	15,187	6,736
Vehicles and railcars	3 - 25	124,948	121,159
Water treatment facilities and equipment	3 - 30	704,666	601,139
Crude oil tanks and related equipment	2 - 30	225,476	218,588
Barges and towboats	5 - 30	103,735	92,712
Information technology equipment	3 - 7	33,082	30,749
Buildings and leasehold improvements	3 - 40	144,567	147,442
Land		63,368	51,816
Tank bottoms and line fill (1)		20,071	20,118
Other	3 - 20	15,018	11,794
Construction in progress		290,832	77,596
		2,264,855	1,861,952
Accumulated depreciation		(420,362)	(343,345)
Net property, plant and equipment		$ 1,844,493	$ 1,518,607

(1) Tank bottoms, which are product volumes required for the operation of storage tanks, are recorded at historical cost. We recover tank bottoms when the storage tanks are removed from service. Line fill, which represents our portion of the product volume required for the operation of the proportionate share of a pipeline we own, is recorded at historical cost.

Amounts in the table above do not include property, plant and equipment and accumulated depreciation related to our former Retail Propane segment, as these amounts have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

The following table summarizes depreciation expense and capitalized interest expense for the periods indicated:

	Year Ended March 31, 2019	2018	2017
		(in thousands)	
Depreciation expense	$ 102,314	$ 100,576	$ 90,474
Capitalized interest expense	$ 482	$ 182	$ 6,887

Amounts in the table above do not include depreciation expense and capitalized interest related to our former Retail Propane segment, as these amounts have been classified within discontinued operations within our consolidated statements of operations (see Note 17).

We record (gains) losses from the sales of property, plant and equipment and any write-downs in value due to impairment within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations. The following table summarizes (gains) losses on the disposal or impairment of property, plant and equipment by segment for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
		(in thousands)	
Crude Oil Logistics (1)	$ 3,489	$ (3,144)	$ 8,124
Water Solutions	3,067	8,117	7,169
Liquids	993	639	92
Refined Products and Renewables	—	15	91
Corporate	—	8	(1)
Total	$ 7,549	$ 5,635	$ 15,475

(1) Amount for the year ended March 31, 2018 primarily relates to a gain related to the sale of excess pipe, partially offset by losses from the disposal of certain assets and the write-down of other assets. Amount for the year ended March 31, 2017 primarily relates to losses from the sale of certain assets, including excess pipe.

Note 6—Goodwill

The following table summarizes changes in goodwill by segment for the periods indicated (in thousands):

	Crude Oil Logistics	Water Solutions	Liquids	Refined Products and Renewables	Total
			(in thousands)		
Balances at March 31, 2017	$ 579,846	$ 424,270	$ 266,046	$ 51,127	$ 1,321,289
Revisions to acquisition accounting	—	195	—	—	195
Impairment	—	—	(116,877)	—	(116,877)
Balances at March 31, 2018	579,846	424,465	149,169	51,127	1,204,607
Acquisitions (Note 4)	—	74,189	20,472	1,328	95,989
Disposals (Note 16)	—	(88,515)	—	—	(88,515)
Impairment	—	—	(66,220)	—	(66,220)
Balances at March 31, 2019	$ 579,846	$ 410,139	$ 103,421	$ 52,455	$ 1,145,861

Fiscal Year 2019 Goodwill Impairment Assessment

Due to the continued decrease in demand for natural gas liquid storage and the resulting decline in revenues and earnings as compared to actual and projected results, we tested the goodwill within our natural gas liquids salt cavern storage reporting unit ("Sawtooth reporting unit"), which is part of our Liquids segment, for impairment at January 1, 2019. We estimated the fair value of our Sawtooth reporting unit based on the income approach, also known as the discounted cash flow method, which utilizes the present value of future expected cash flows to estimate the fair value. The future cash flows of our Sawtooth reporting unit were projected based upon estimates as of the test date of future revenues, operating expenses and cash outflows necessary to support these cash flows, including working capital and maintenance capital expenditures. We also considered expectations regarding: (i) expected storage volumes, which are assumed to increase in the coming years due to increased production of natural gas liquids, (ii) expected propane and butane prices, (iii) expected rental fees and (iv) the addition of storing refined products (which we acquired as part of the sale of a portion of the reporting unit (see Note 16). We assumed that commodity prices would be flat through the duration of the model and an average increase of approximately 7% increase in rental fees per year starting in April 2020, and held such prices and fees flat for periods in our model beyond our 2024 fiscal year. For expenses, we assumed an increase consistent with the increase in storage volumes, and maintenance capital was held flat throughout the model. The discount rate used in our discounted cash flow method was a risk adjusted weighted average cost of capital calculated as of January 1, 2019 of approximately 13.1%. The discounted cash flow results indicated that the estimated fair value of our Sawtooth reporting unit was less than its carrying value by approximately 35.2% at January 1, 2019.

During the three months ended March 31, 2019, we recorded a goodwill impairment charge of $66.2 million, which was a write-off of the remaining goodwill within the Sawtooth reporting unit. The goodwill impairment charge was recorded within loss (gain) on disposal or impairment of assets, net, in our consolidated statement of operations.

We performed a qualitative assessment as of January 1, 2019 to determine whether it was more likely than not that the fair value of each reporting unit was greater than the carrying value of the reporting unit. Based on these qualitative assessments, we determined that the fair value of each of these reporting units was more likely than not greater than the carrying value of the reporting units, other than the Sawtooth reporting unit as previously described.

Fiscal Year 2018 Goodwill Impairment Assessment

Due to the decreased demand for natural gas liquid storage and resulting decline in revenues and earnings as compared to actual and projected results of prior and future periods, we tested the goodwill within our Sawtooth reporting unit, which is part of our Liquids segment, for impairment at September 30, 2017. We estimated the fair value of our Sawtooth reporting unit based on the income approach, also known as the discounted cash flow method, which utilizes the present value of future expected cash flows to estimate the fair value. The future cash flows of our Sawtooth reporting unit were projected based upon estimates as of the test date of future revenues, operating expenses and cash outflows necessary to support these cash flows, including working capital and maintenance capital expenditures. We also considered expectations regarding: (i) expected storage volumes, which are assumed to increase in the coming years due to increased production of natural gas liquids, (ii) expected propane and butane prices and (iii) expected rental fees. We assumed a 2% per year increase in commodity prices and a 4% increase in rental fees per year starting in April 2018, and held such prices and fees flat for periods in our model beyond our 2023 fiscal year. For expenses, we assumed an increase consistent with the increase in storage volumes, and maintenance capital was held flat throughout the model. The discount rate used in our discounted cash flow method was a risk adjusted weighted average cost of capital calculated as of September 30, 2017 of 12%. The discounted cash flow results indicated that the estimated fair value of our Sawtooth reporting unit was less than its carrying value by approximately 32% at September 30, 2017.

During the three months ended September 30, 2017, we recorded a goodwill impairment charge of $116.9 million, which was recorded within loss (gain) on disposal or impairment of assets, net , in our consolidated statement of operations. At September 30, 2017, our Sawtooth reporting unit had a goodwill balance of $66.2 million.

In Note 16, we discuss a transaction in which we formed a joint venture which included our Sawtooth salt dome storage facility. As a result of this transaction, we tested the goodwill of our Sawtooth reporting unit, immediately prior to the closing of this transaction, for impairment. As of March 30, 2018, our Sawtooth reporting unit had a goodwill balance of $66.2 million. Similar to the analysis we performed as of September 30, 2017, as discussed above, we estimated the fair value of our Sawtooth reporting unit based on the income approach, also known as the discounted cash flow method, which utilizes the present value of future expected cash flows to estimate the fair value. The future cash flows of our Sawtooth reporting unit were projected based upon estimates as of the test date of future revenues, operating expenses and cash outflows necessary to support these cash flows, including working capital and maintenance capital expenditures. We also considered expectations regarding: (i) expected storage volumes, which are assumed to increase in the coming years due to increased production of natural gas liquids, (ii) expected propane and butane prices and (iii) expected rental fees. We assumed a 2% per year increase in commodity prices and a 4% increase in rental fees per year starting in April 2018, and held such prices and fees flat for periods in our model beyond our 2023 fiscal year. For expenses, we assumed an increase consistent with the increase in storage volumes, and maintenance capital was held flat throughout the model. The discount rate used in our discounted cash flow method was a risk adjusted weighted average cost of capital calculated as of March 30, 2018 of 12.4%. The discounted cash flow results indicated that the estimated fair value of our Sawtooth reporting unit was greater than its carrying value by approximately 2% at March 30, 2018.

Our estimated fair value is predicated upon management’s assumption of the growth in the production of natural gas liquids and the decline in the use of railcars to store natural gas liquids. We used these assumptions to estimate the demand for storage at our facility and the revenue generated by customers reserving capacity at our facility. Due to the current volatility in commodity prices and the excess railcars currently in the market, we believe it is reasonably possible that the need for underground storage we estimate in our model does not materialize, such that our estimate of fair value could change and result in further impairment of the goodwill in our Sawtooth reporting unit.

We performed a qualitative assessment as of January 1, 2018 to determine whether it was more likely than not that the fair value of each reporting unit was greater than the carrying value of the reporting unit. Based on these qualitative assessments, we determined that the fair value of each of these reporting units was more likely than not greater than the carrying value of the reporting units, other than the Sawtooth reporting unit as previously described.

Fiscal Year 2017 Goodwill Impairment Assessment

We performed a qualitative assessment as of January 1, 2017 to determine whether it was more likely than not that the fair value of each reporting unit was greater than the carrying value of the reporting unit. Based on these qualitative assessments, we determined that the fair value of each of these reporting units was more likely than not greater than the carrying value of the reporting units.

Fiscal Year 2016 Goodwill Impairment Assessment

As discussed previously, during the three months ended June 30, 2016, we finalized our goodwill impairment analysis of our Water Solutions reporting unit, with the assistance of a third party valuation firm. As a result of finalizing our analysis, we determined that we needed to reverse $124.7 million of the previously recorded goodwill impairment estimate of $380.2 million recorded during the year ended March 31, 2016. The adjustment was due primarily to the change in the fair value of our customer relationship intangible assets. With the assistance of the third party valuation firm, inputs such as revenue growth rates and attrition rates related to existing customers were refined to better correlate with our historical revenue growth and attrition rates of our existing customers in our Water Solutions reporting unit. This change resulted in a lower fair value allocated to customer relationships and higher value to goodwill than in our preliminary calculation. We recorded the adjustment within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations.

Note 7—Intangible Assets

Our intangible assets consist of the following at the dates indicated:

		March 31, 2019			March 31, 2018		
Description	**Amortizable Lives**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**
	(in years)	**(in thousands)**					
Amortizable:							
Customer relationships	3 - 30	$ 747,432	$ (370,072)	$ 377,360	$ 718,763	$ (328,666)	$ 390,097
Customer commitments	10	310,000	(74,917)	235,083	310,000	(43,917)	266,083
Pipeline capacity rights	30	161,785	(22,438)	139,347	161,785	(17,045)	144,740
Rights-of-way and easements	1 - 40	73,409	(4,509)	68,900	63,995	(3,214)	60,781
Water rights	14	64,868	(3,018)	61,850	—	—	—
Executory contracts and other agreements	3 - 30	47,230	(17,212)	30,018	42,919	(15,424)	27,495
Non-compete agreements	2 - 32	12,723	(2,570)	10,153	5,465	(706)	4,759
Debt issuance costs (1)	5	42,345	(29,521)	12,824	40,992	(24,593)	16,399
Total amortizable		1,459,792	(524,257)	935,535	1,343,919	(433,565)	910,354
Non-amortizable:							
Trade names		2,800	—	2,800	2,800	—	2,800
Total		$ 1,462,592	$ (524,257)	$ 938,335	$ 1,346,719	$ (433,565)	$ 913,154

(1) Includes debt issuance costs related to the Revolving Credit Facility (as defined herein). Debt issuance costs related to fixed-rate notes are reported as a reduction of the carrying amount of long-term debt.

Amounts in the table above do not include intangible assets and accumulated amortization related to our former Retail Propane segment, as these amounts have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

The weighted-average remaining amortization period for intangible assets is approximately 13.4 years.

Write off of Intangible Assets

During the year ended March 31, 2018, we wrote off $1.8 million related to the non-compete agreement which was terminated as part of our acquisition of the remaining interest in NGL Solids Solutions, LLC. In connection with the amendment and restatement of the Credit Agreement (as defined herein) in February 2017, we wrote off $4.5 million of deferred debt issuance costs. During the year ended March 31, 2017, we wrote-off $5.2 million related to the value of an indefinite-lived trade name intangible asset in conjunction with finalizing our goodwill impairment analysis. In addition, as a result of terminating the development agreement in the Water Solutions segment in June 2016 (see Note 16), we incurred a loss of $5.8 million to write off the water facility development agreement. The losses for the years ended March 31, 2018 and 2017 are reported within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations.

Amortization expense is as follows for the periods indicated:

	Year Ended March 31,		
Recorded In	**2019**	**2018**	**2017**
		(in thousands)	
Depreciation and amortization	$ 110,546	$ 108,444	$ 89,765
Cost of sales	5,619	6,099	6,828
Interest expense	4,928	4,568	4,471
Total	$ 121,093	$ 119,111	$ 101,064

Amounts in the table above do not include amortization expense related to our former Retail Propane segment, as these amounts have been classified within discontinued operations within our consolidated statements of operations (see Note 17).

Expected amortization of our intangible assets is as follows (in thousands):

Year Ending March 31,	
2020	$ 122,159
2021	109,849
2022	97,011
2023	88,991
2024	82,851
Thereafter	434,674
Total	$ 935,535

Note 8—Long-Term Debt

Our long-term debt consists of the following at the dates indicated:

	March 31, 2019			March 31, 2018		
	Face Amount	Unamortized Debt Issuance Costs (1)	Book Value	Face Amount	Unamortized Debt Issuance Costs (1)	Book Value
	(in thousands)					
Revolving credit facility:						
Expansion capital borrowings	$ 275,000	$ —	$ 275,000	$ —	$ —	$ —
Working capital borrowings	896,000	—	896,000	969,500	—	969,500
Senior unsecured notes:						
5.125% Notes due 2019 ("2019 Notes")	—	—	—	353,424	(1,653)	351,771
6.875% Notes due 2021 ("2021 Notes")	—	—	—	367,048	(4,499)	362,549
7.500% Notes due 2023 ("2023 Notes")	607,323	(6,916)	600,407	615,947	(8,542)	607,405
6.125% Notes due 2025 ("2025 Notes")	389,135	(5,092)	384,043	389,135	(5,951)	383,184
Other long-term debt	5,331	—	5,331	5,977	—	5,977
	2,172,789	(12,008)	2,160,781	2,701,031	(20,645)	2,680,386
Less: Current maturities	648	—	648	646	—	646
Long-term debt	$ 2,172,141	$ (12,008)	$ 2,160,133	$ 2,700,385	$ (20,645)	$ 2,679,740

(1) Debt issuance costs related to the Revolving Credit Facility are reported within intangible assets, rather than as a reduction of the carrying amount of long-term debt.

Amounts in the table above do not include long-term debt related to our former Retail Propane segment, as these amounts have been classified as liabilities held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

Amortization expense for debt issuance costs related to long-term debt in the table above was $4.3 million, $6.1 million and $3.3 million during the years ended March 31, 2019, 2018 and 2017.

Expected amortization of debt issuance costs is as follows (in thousands):

Year Ending March 31,	
2020	$ 2,371
2021	2,367
2022	2,367
2023	2,367
2024	1,744
Thereafter	792
Total	$ 12,008

Credit Agreement

We are party to a $1.765 billion credit agreement (the “Credit Agreement”) with a syndicate of banks. As of March 31, 2019, the Credit Agreement includes a revolving credit facility to fund working capital needs, which had a capacity of $1.250 billion for cash borrowings and letters of credit (the “Working Capital Facility”), and a revolving credit facility to fund acquisitions and expansion projects, which had a capacity of $515.0 million (the “Expansion Capital Facility,” and together with the Working Capital Facility, the “Revolving Credit Facility”). The Revolving Credit Facility allows us to reallocate amounts between the Expansion Capital Facility and Working Capital Facility. We had letters of credit of $143.4 million on the Working Capital Facility at March 31, 2019. The capacity under the Working Capital Facility may be limited by a “borrowing base” (as defined in the Credit Agreement) which is calculated based on the value of certain working capital items at any point in time.

The commitments under the Credit Agreement expire on October 5, 2021. We have the right to prepay outstanding borrowings under the Credit Agreement without incurring any penalties, and prepayments of principal may be required if we enter into certain transactions to sell assets or obtain new borrowings. The Credit Agreement is secured by substantially all of our assets.

At March 31, 2019, the borrowings under the Credit Agreement had a weighted average interest rate of 4.39%, calculated as the weighted average LIBOR rate of 2.49% plus a margin of 1.75% for LIBOR borrowings and the prime rate of 5.50% plus a margin of 0.75% on alternate base rate borrowings. At March 31, 2019, the interest rate in effect on letters of credit was 1.75%. Commitment fees are charged at a rate ranging from 0.375% to 0.50% on any unused capacity.

On July 5, 2018, we amended the Credit Agreement. In the amendment, the lenders consented to, subject to the consummation of the Retail Propane disposition, release NGL Propane, LLC and its wholly-owned subsidiaries from its guaranty and other obligations under the loan documents, among other things. In return, the Partnership agreed to use the net proceeds from the Retail Propane disposition to pay down existing indebtedness no later than five business days after the consummation of the Retail Propane disposition.

On February 6, 2019, we amended the Credit Agreement, to, among other things, reset the basket for the repurchase of common units with a limit of $150 million in aggregate during the remaining term of the Credit Agreement, not to exceed $50 million per fiscal quarter, so long as, both immediately before and after giving pro forma effect to the repurchases, the Partnership's Leverage Ratio (as defined in the Credit Agreement) is less than 3.25x and Revolving Availability (also as defined in the Credit Agreement) is greater than or equal to $200 million. In addition, the amendment decreases the Maximum Total Leverage Indebtedness Ratio beginning September 30, 2019 with a further decrease beginning March 31, 2020 (as presented in the table below), and amends the defined term "Consolidated EBITDA" to exclude the "Gavilon Energy EPA Settlement" (as defined in the Credit Agreement) solely for the two quarters ending December 31, 2018 and March 31, 2019.

The following table summarizes the debt covenant levels specified in the Credit Agreement as of March 31, 2019 (as modified on February 6, 2019):

Period Beginning	Leverage Ratio (1)	Senior Secured Leverage Ratio (1)	Interest Coverage Ratio (2)	Total Leverage Indebtedness Ratio (1)
March 31, 2019	4.50	3.25	2.75	6.50
September 30, 2019	4.50	3.25	2.75	6.25
March 31, 2020 and thereafter	4.50	3.25	2.75	6.00

(1) Represents the maximum ratio for the period presented.

(2) Represents the minimum ratio for the period presented.

At March 31, 2019, our leverage ratio was approximately 2.63 to 1, our senior secured leverage ratio was approximately 0.58 to 1, our interest coverage ratio was approximately 3.70 to 1 and our total leverage indebtedness ratio was approximately 4.48 to 1.

The Credit Agreement contains various customary representations, warranties, and additional covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the Credit Agreement may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) a breach by the Partnership or its subsidiaries of any material representation or warranty or any covenant made in the Credit Agreement, or (iii) certain events of bankruptcy or insolvency.

We were in compliance with the covenants under the Credit Agreement at March 31, 2019.

Senior Secured Notes

On June 19, 2012, we entered into the Note Purchase Agreement (as amended, the "Senior Secured Notes Purchase Agreement") whereby we issued $250.0 million of senior secured notes in a private placement (the "Senior Secured Notes"). The Senior Secured Notes paid interest at a fixed rate of 6.65% which was payable quarterly. The Senior Secured Notes were required to be repaid in semi-annual installments of $25.0 million beginning on December 19, 2017 and ending on the maturity date of June 19, 2022. We had the option to prepay outstanding principal, although we would incur a prepayment penalty. On December 29, 2017, we repurchased all of the remaining outstanding Senior Secured Notes. See below for the details related to the repurchase.

Repurchases

The following table summarizes repurchases of Senior Secured Notes for the period indicated:

		Year Ended March 31, 2018
		(in thousands)
Senior Secured Notes		
Notes repurchased	$	230,500
Cash paid (excluding payments of accrued interest)	$	250,179
Loss on early extinguishment of debt (1)	$	(23,971)

(1) Loss on the early extinguishment of debt for the Senior Secured Notes during the year ended March 31, 2018 is inclusive of the write off of debt issuance costs of $4.3 million. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

Prior to the December 29, 2017 repurchase of all the remaining outstanding Senior Secured Notes, we made a semi-annual principal installment payment of $19.5 million on December 19, 2017.

Senior Unsecured Notes

The senior unsecured notes include, as defined below, the 2019 Notes, 2021 Notes, 2023 Notes, 2025 Notes and 2026 Notes (collectively, the "Senior Unsecured Notes").

The Partnership and NGL Energy Finance Corp. are co-issuers of the Senior Unsecured Notes, and the obligations under the Senior Unsecured Notes are fully and unconditionally guaranteed by certain of our existing and future restricted subsidiaries that incur or guarantee indebtedness under certain of our other indebtedness, including the Revolving Credit Facility. The indentures governing the Senior Unsecured Notes contain various customary covenants, including, (i) pay distributions on, purchase or redeem our common equity or purchase or redeem our subordinated debt, (ii) incur or guarantee additional indebtedness or issue preferred units, (iii) create or incur certain liens, (iv) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us, (v) consolidate, merge or transfer all or substantially all of our assets, and (vi) engage in transactions with affiliates.

Our obligations under the Senior Unsecured Notes may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) experiencing an event of default on certain other debt agreements, or (iii) certain events of bankruptcy or insolvency.

Issuances

On July 9, 2014, we issued $400.0 million of 5.125% Senior Unsecured Notes Due 2019 (the "2019 Notes"). Interest is payable on January 15 and July 15 of each year. The 2019 Notes were redeemed on March 15, 2019. See further discussion below.

On October 16, 2013, we issued $450.0 million of 6.875% Senior Unsecured Notes Due 2021 (the "2021 Notes"). Interest is payable on April 15 and October 15 of each year. The 2021 Notes were redeemed on October 16, 2018. See further discussion below.

On October 24, 2016, we issued $700.0 million of 7.50% Senior Unsecured Notes Due 2023 (the "2023 Notes"). Interest is payable on May 1 and November 1 of each year. The registration of the 2023 Notes became effective on July 11, 2017. The 2023 Notes mature on November 1, 2023.

On February 22, 2017, we issued $500.0 million of 6.125% Senior Unsecured Notes Due 2025 (the "2025 Notes"). Interest is payable on March 1 and September 1 of each year. The registration of the 2025 Notes became effective on July 11, 2017. The 2025 Notes mature on March 1, 2025.

On April 9, 2019, we issued $450.0 million of 7.50% Senior Unsecured Notes Due 2026 (the "2026 Notes") in a private placement. The 2026 Notes bear interest, which is payable on April 15 and October 15 of each year, beginning on

October 15, 2019. We received net proceeds of $441.8 million, after the initial purchasers' discount of $6.8 million and offering costs of $1.5 million. The 2026 Notes mature on April 15, 2026.

The Partnership and NGL Energy Finance Corp. are co-issuers of the 2026 Notes, and the obligations under the 2026 Notes are fully and unconditionally guaranteed by certain of our existing and future restricted subsidiaries that incur or guarantee indebtedness under certain of our other indebtedness, including the Revolving Credit Facility. The indenture governing the 2026 Notes contains various customary covenants, including, (i) pay distributions on, purchase or redeem our common equity or purchase or redeem our subordinated debt, (ii) incur or guarantee additional indebtedness or issue preferred units, (iii) create or incur certain liens, (iv) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us, (v) consolidate, merge or transfer all or substantially all of our assets, and (vi) engage in transactions with affiliates.

Our obligations under the indenture may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) experiencing an event of default on certain other debt agreements, or (iii) certain events of bankruptcy or insolvency.

We have the option to redeem all or a portion of the 2026 Notes at any time on or after April 15, 2022 at fixed redemption prices beginning at 103.750% on such date and declining annually and ratably to par for redemptions occurring on or after April 15, 2024 plus accrued and unpaid interest. At any time prior to April 15, 2022, we may redeem all or a portion of the 2026 Notes, at a redemption price equal to the "make whole price" specified in the indenture, plus accrued and unpaid interest.

In connection with the closing of the offering of the 2026 Notes, the Partnership entered into a registration rights agreement (the "Registration Rights Agreement"). Under the Registration Rights Agreement, the Partnership agreed to file a registration statement with the Securities and Exchange Commission ("SEC") so that holders can exchange the 2026 Notes for registered notes that have substantially identical terms as the 2026 Notes and evidence the same indebtedness as the 2026 Notes. In addition, the subsidiary guarantors agreed to exchange the guarantee related to the 2026 Notes for a registered guarantee having substantially the same terms as the original guarantees. The Partnership is obligated to use commercially reasonable efforts to file an exchange offer registration statement with respect to the exchange notes and exchange guarantees and cause such exchange offer registration statement to become effective on or prior to 365 days after the closing of this offering. If the Partnership fails to satisfy this obligation, it will be required to pay to the holders of the 2026 Notes liquidated damages in an amount equal 0.25% per annum on the principal amount of the 2026 Notes held by such holder during the 90-day period immediately following the occurrence of such registration default, and such amount shall increase by 0.25% per annum at the end of such 90-day period.

Redemptions

The following table summarizes redemptions of Senior Unsecured Notes for the period indicated:

	Year Ended March 31, 2019 (in thousands)
2019 Notes (1)	
Notes redeemed	$ 328,005
Cash paid (excluding payments of accrued interest)	$ 329,719
Loss on early extinguishment of debt	$ (2,113)
2021 Notes (2)	
Notes redeemed	$ 367,048
Cash paid (excluding payments of accrued interest)	$ 373,358
Loss on early extinguishment of debt	$ (10,130)

(1) On March 15, 2019, we redeemed all of the remaining outstanding 2019 Notes. Loss on the early extinguishment of debt for the 2019 Notes during the year ended March 31, 2019 is inclusive of the write off of debt issuance costs of $0.4 million. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(2) On October 16, 2018, we redeemed all of the remaining outstanding 2021 Notes. Loss on the early extinguishment of debt for the 2021 Notes during the year ended March 31, 2019 is inclusive of the write off of debt issuance costs of $3.8 million. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

Repurchases

The following table summarizes repurchases of Senior Unsecured Notes for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
2019 Notes			
Notes repurchased	$ 25,419	$ 26,034	$ 9,009
Cash paid (excluding payments of accrued interest)	$ 25,406	$ 26,002	$ 7,099
(Loss) gain on early extinguishment of debt (1)	$ (34)	$ (140)	$ 1,759
2021 Notes			
Notes repurchased	$ —	$ —	$ 21,241
Cash paid (excluding payments of accrued interest)	$ —	$ —	$ 14,094
Gain on early extinguishment of debt (2)	$ —	$ —	$ 6,748
2023 Notes			
Notes repurchased	$ 8,624	$ 84,053	$ —
Cash paid (excluding payments of accrued interest)	$ 8,575	$ 83,967	$ —
Loss on early extinguishment of debt (3)	$ (63)	$ (1,136)	$ —
2025 Notes			
Notes repurchased	$ —	$ 110,865	$ —
Cash paid (excluding payments of accrued interest)	$ —	$ 107,050	$ —
Gain on early extinguishment of debt (4)	$ —	$ 2,046	$ —

(1) (Loss) gain on early extinguishment of debt for the 2019 Notes during the years ended March 31, 2019, 2018 and 2017 is inclusive of the write off of debt issuance costs of less than $0.1 million $0.2 million and $0.2 million, respectively. The (loss) gain is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(2) Gain on early extinguishment of debt for the 2021 Notes during the year ended March 31, 2017 is inclusive of the write off of debt issuance costs of $0.4 million. The gain is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(3) Loss on early extinguishment of debt for the 2023 Notes during the years ended March 31, 2019 and 2018 is inclusive of the write off of debt issuance costs of $0.1 million and $1.2 million, respectively. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(4) Gain on early extinguishment of debt for the 2025 Notes during the year ended March 31, 2018 is inclusive of the write off of debt issuance costs of $1.8 million. The gain is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

Compliance

At March 31, 2019, we were in compliance with the covenants under all of the Senior Unsecured Notes indentures.

Other Long-Term Debt

We have other notes payable related to equipment financing. The interest rates on these instruments range from 4.13% to 7.10% per year and have an aggregate principal balance of $5.3 million at March 31, 2019. Equipment loans totaling $41.7 million were paid off on March 30, 2017, resulting in a loss on the early extinguishment of debt of $1.6 million, which was net of $0.1 million of debt issuance costs and $1.5 million of prepayment penalties. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

Debt Maturity Schedule

The scheduled maturities of our long-term debt are as follows at March 31, 2019:

Year Ending March 31,	Revolving Credit Facility	Senior Unsecured Notes	Other Long-Term Debt	Total
	(in thousands)			
2020	$ —	$ —	$ 648	$ 648
2021	—	—	4,683	4,683
2022	1,171,000	—	—	1,171,000
2023	—	—	—	—
2024	—	607,323	—	607,323
Thereafter	—	389,135	—	389,135
Total	$ 1,171,000	$ 996,458	$ 5,331	$ 2,172,789

Note 9—Commitments and Contingencies

Legal Contingencies

In August 2015, LCT Capital, LLC (“LCT”) filed a lawsuit against NGL Energy Holdings LLC (the “GP”) and the Partnership seeking payment for investment banking services relating to the purchase of TransMontaigne Inc. and related assets in July 2014. After pre-trial rulings, LCT was limited to pursuing claims of (i) *quantum meruit* (the value of the services rendered by LCT) and (ii) fraudulent misrepresentation against the defendants. Following a jury trial conducted in Delaware state court from July 23, 2018 through August 1, 2018, the jury returned a verdict consisting of an award of $4.0 million for *quantum meruit* and $29.0 million for fraudulent misrepresentation, subject to statutory interest. The GP and the Partnership contend that the jury verdict, at least in respect of fraudulent misrepresentation, is not supportable by either controlling law or the evidentiary record. Both defendants have a pending motion for judgment as a matter of law on the fraudulent misrepresentation claim and plan to file post-verdict motions as appropriate before the trial court, and, if need be, will file an appeal to the Delaware Supreme Court. It is our position that the awards, even if they each stand, are not cumulative. Any allocation of the ultimate verdict award between the GP and the Partnership will be made by the board of directors once all information is available to it and after the post-trial and any appellate process has run its course and the verdict is final as a matter of law. Because the Partnership is a named defendant in the lawsuit, and any judgment ultimately awarded would be joint and several with the GP, we have determined that it is probable that the Partnership could be liable for a portion of this judgment. At this time, we believe the amount that could be allocated to the Partnership would not be material as it is estimated to be less than $4.0 million. As of March 31, 2019, we have accrued $2.5 million related to this matter.

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In the opinion of our management, the ultimate resolution of these claims, legal actions, and complaints, after consideration of amounts accrued, insurance coverage, and other arrangements, is not expected to have a material adverse effect on our consolidated financial position, results of operations or cash flows. However, the outcome of such matters is inherently uncertain, and estimates of our liabilities may change materially as circumstances develop.

Environmental Matters

At March 31, 2019, we have an environmental liability, measured on an undiscounted basis, of $2.5 million, which is recorded within accrued expenses and other payables in our consolidated balance sheet. Our operations are subject to extensive federal, state, and local environmental laws and regulations. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in our business, and there can be no assurance that we will not incur significant costs. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs. Accordingly, we have adopted policies, practices, and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials designed to prevent material environmental or other damage, and to limit the financial liability that could result from such events. However, some risk of environmental or other damage is inherent in our business.

In 2015, as previously disclosed, the U.S. Environmental Protection Agency (“EPA”) informed NGL Crude Logistics, LLC, formerly known as Gavilon, LLC (“Gavilon Energy”), of alleged violations that occurred in 2011 by Gavilon Energy of the Clean Air Act's renewable fuel standards regulations (prior to its acquisition by us in December 2013). On October 4, 2016, the U.S. Department of Justice, acting at the request of the EPA, filed a civil complaint in the Northern District of Iowa against Gavilon Energy and one of its then suppliers, Western Dubuque Biodiesel LLC ("Western Dubuque"). Consistent with the earlier allegations by the EPA, the civil complaint related to transactions between Gavilon Energy and Western Dubuque and the generation of biodiesel renewable identification numbers ("RINs") sold by Western Dubuque to Gavilon Energy in 2011. On December 19, 2016, we filed a motion to dismiss the complaint. On January 9, 2017, the EPA filed an amended complaint. The amended complaint seeks an order declaring Western Dubuque's RINs invalid and requiring the defendants to retire an equivalent number of valid RINs and that the defendants pay statutory civil penalties. On January 23, 2017, we filed a motion to dismiss the amended complaint. On May 24, 2017, the court denied our motion to dismiss. Subsequently, the EPA filed a second amended complaint seeking an order declaring Western Dubuque's RINs invalid, an order requiring us to retire an equivalent number of valid RINs and an award against us of statutory civil penalties. In May 2018, the parties completed briefing on cross-motions for summary judgment concerning liability issues in the case. On July 3, 2018, the Court denied our summary judgment motion and largely granted the plaintiff's two summary judgment motions on liability. On July 19, 2018, Gavilon Energy reached an agreement in principle with the EPA regarding the terms of a settlement of the case, which was memorialized in a consent decree lodged to the Court on September 27, 2018. Such terms will result in Gavilon Energy paying cash of $25.0 million and retiring 36 million RINs, over a twelve-month period. The consent decree was approved by the Court on November 8, 2018. The consent decree resolves all matters between Gavilon Energy and the EPA in connection with the above-described complaint. During the year ended March 31, 2019, we paid the EPA $12.5 million and retired all 36 million RINs. As of March 31, 2019, we have an accrual, which is included within accrued expenses and other payables in our consolidated balance sheet, of $12.5 million.

Asset Retirement Obligations

We have contractual and regulatory obligations at certain facilities for which we have to perform remediation, dismantlement, or removal activities when the assets are retired. Our liability for asset retirement obligations is discounted to present value. To calculate the liability, we make estimates and assumptions about the retirement cost and the timing of retirement. Changes in our assumptions and estimates may occur as a result of the passage of time and the occurrence of future events. The following table summarizes changes in our asset retirement obligation, which is reported within other noncurrent liabilities in our consolidated balance sheets (in thousands):

Balance at March 31, 2017	$	8,181
Liabilities incurred		592
Liabilities assumed in acquisitions		21
Liabilities settled		(549)
Accretion expense		888
Balance at March 31, 2018		9,133
Liabilities incurred		586
Liabilities assumed in acquisitions		438
Liabilities associated with disposed assets (1)		(585)
Liabilities settled		(546)
Accretion expense		697
Balance at March 31, 2019	$	9,723

(1) This amount primarily relates to the sales of our Bakken and South Pecos water disposal businesses (see Note 16).

In addition to the obligations described above, we may be obligated to remove facilities or perform other remediation upon retirement of certain other assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminable. We will record an asset retirement obligation for these assets in the periods in which settlement dates are reasonably determinable.

Operating Leases

We have executed various noncancelable operating lease agreements for product storage, office space, vehicles, real estate, railcars, and equipment. The following table summarizes future minimum lease payments under these agreements at March 31, 2019 (in thousands):

Year Ending March 31,		
2020	$	127,718
2021		105,697
2022		83,595
2023		54,599
2024		18,841
Thereafter		41,845
Total	$	432,295

Amounts in the table above do not include operating leases related to our former Retail Propane segment (see Note 17).

Rental expense relating to operating leases was $150.7 million, $122.4 million, and $122.0 million during the years ended March 31, 2019, 2018 and 2017, respectively. Amounts do not include rental expense related to our former Retail Propane segment, as these amounts have been classified within discontinued operations within our consolidated statements of operations (see Note 17).

Pipeline Capacity Agreements

We have executed noncancelable agreements with crude oil pipeline operators, which guarantee us minimum monthly shipping capacity on the pipelines. As a result, we are required to pay the minimum shipping fees if actual shipments are less than our allotted capacity. Under certain agreements we have the ability to recover minimum shipping fees previously paid if our shipping volumes exceed the minimum monthly shipping commitment during each month remaining under the agreement, with some contracts containing provisions that allow us to continue shipping up to six months after the maturity date of the contract in order to recapture previously paid minimum shipping delinquency fees. We currently have an asset recorded in other noncurrent assets in our consolidated balance sheet for minimum shipping fees paid in both the current and previous periods that are expected to be recovered in future periods by exceeding the minimum monthly volumes (see Note 2).

The future minimum throughput payments under these agreements at March 31, 2019 are $43.2 million. The payments for these agreements will be completed at the end of fiscal year 2020. Of the total future minimum throughput payments, a third party has agreed to assume all rights and privileges and to be fully responsible for any minimum shipping fees due for actual shipments that are less than our allotted capacity related to $30.0 million of the fiscal year 2020 amount under a definitive agreement we signed during the three months ended June 30, 2018 (see Note 13).

Construction Commitments

At March 31, 2019, we had construction commitments of $29.7 million.

Sales and Purchase Contracts

We have entered into product sales and purchase contracts for which we expect the parties to physically settle and deliver the inventory in future periods.

At March 31, 2019, we had the following commodity purchase commitments (in thousands):

	Crude Oil (1)		Natural Gas Liquids	
	Value	Volume (in barrels)	Value	Volume (in gallons)
Fixed-Price Commodity Purchase Commitments:				
2020	$ 60,227	1,040	$ 5,033	7,545
2021	—	—	265	378
Total	$ 60,227	1,040	$ 5,298	7,923
Index-Price Commodity Purchase Commitments:				
2020	$ 1,703,112	30,363	$ 564,013	1,023,998
2021	526,420	10,227	1,199	2,152
2022	411,071	8,264	—	—
2023	269,990	5,482	—	—
2024	200,022	4,110	—	—
Total	$ 3,110,615	58,446	$ 565,212	1,026,150

(1) Our crude oil index-price purchase commitments exceed our crude oil index-price sales commitments (presented below) due primarily to our long-term purchase commitments for crude oil that we purchase and ship on the Grand Mesa Pipeline. As these purchase commitments are deliver-or-pay contracts, whereby our counterparty is required to pay us for any volumes not delivered, we have not entered into corresponding long-term sales contracts for volumes we may not receive.

At March 31, 2019, we had the following commodity sale commitments (in thousands):

	Crude Oil		Natural Gas Liquids	
	Value	Volume (in barrels)	Value	Volume (in gallons)
Fixed-Price Commodity Sale Commitments:				
2020	$ 63,759	1,090	$ 45,626	52,766
2021	—	—	1,395	1,580
2022	—	—	86	100
Total	$ 63,759	1,090	$ 47,107	54,446
Index-Price Commodity Sale Commitments:				
2020	$ 1,240,074	20,500	$ 594,877	778,454
2021	—	—	1,634	2,183
Total	$ 1,240,074	20,500	$ 596,511	780,637

We account for the contracts shown in the tables above using the normal purchase and normal sale election. Under this accounting policy election, we do not record the physical contracts at fair value at each balance sheet date; instead, we record the purchase or sale at the contracted value once the delivery occurs. Contracts in the tables above may have offsetting derivative contracts (described in Note 11) or inventory positions (described in Note 2).

Certain other forward purchase and sale contracts do not qualify for the normal purchase and normal sale election. These contracts are recorded at fair value in our consolidated balance sheet and are not included in the tables above. These contracts are included in the derivative disclosures in Note 11, and represent $86.5 million of our prepaid expenses and other current assets and $100.3 million of our accrued expenses and other payables at March 31, 2019.

Note 10—Equity

Partnership Equity

The Partnership's equity consists of a 0.1% general partner interest and a 99.9% limited partner interest, which consists of common units. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 0.1% general partner interest. Our general partner is not required to guarantee or pay any of our debts or obligations.

General Partner Contributions

In connection with the issuance of common units for the vesting of restricted units and warrants that were exercised for common units during the year ended March 31, 2019, we issued 3,039 notional units to our general partner for less than $0.1 million in order to maintain its 0.1% interest in us.

In connection with the issuance of common units for the vesting of restricted units and warrants that were exercised for common units during the year ended March 31, 2018, we issued 1,294 notional units to our general partner for less than $0.1 million in order to maintain its 0.1% interest in us.

In connection with the issuance of common units for the vesting of restricted units, ATM Program (as defined herein) and the equity issuance in February 2017, as discussed within this note, as well as common units issued for a retail propane acquisition during the year ended March 31, 2017, we issued 16,026 notional units to our general partner for $0.3 million in order to maintain its 0.1% interest in us.

Equity Issuances

On August 24, 2016, we entered into an equity distribution agreement in connection with an at-the-market program (the "ATM Program") pursuant to which we may issue and sell up to $200.0 million of common units. This ATM Program is registered with the SEC on an effective registration statement on Form S-3. During the year ended March 31, 2017, we sold 3,321,135 common units for net proceeds of $64.4 million (net of offering costs of $0.9 million). We did not sell any common units under the ATM Program during the years ended March 31, 2019 and 2018. As of March 31, 2019, approximately $134.7 million remained available for sale under the ATM Program.

On February 22, 2017, we completed a public offering of 10,120,000 common units. We received net proceeds of $222.5 million (net of offering costs of $11.8 million).

Common Unit Repurchase Program

On August 29, 2017, the board of directors of our general partner authorized a common unit repurchase program, under which we may repurchase up to $15.0 million of our outstanding common units through December 31, 2017 from time to time in the open market or in other privately negotiated transactions. Under this program, we repurchased 1,516,848 common units for an aggregate price of $15.0 million, including commissions. This program ended on December 31, 2017.

Our Distributions

The following table summarizes distributions declared on our common units during the last three fiscal years:

Date Declared	Record Date	Payment Date	Amount Per Unit	Amount Paid to Limited Partners	Amount Paid to General Partner
				(in thousands)	(in thousands)
April 21, 2016	May 3, 2016	May 13, 2016	$ 0.3900	$ 40,626	$ 70
July 21, 2016	August 4, 2016	August 12, 2016	$ 0.3900	$ 41,146	$ 71
October 20, 2016	November 4, 2016	November 14, 2016	$ 0.3900	$ 41,907	$ 72
January 19, 2017	February 3, 2017	February 14, 2017	$ 0.3900	$ 42,923	$ 74
April 24, 2017	May 8, 2017	May 15, 2017	$ 0.3900	$ 46,870	$ 80
July 20, 2017	August 4, 2017	August 14, 2017	$ 0.3900	$ 47,460	$ 81
October 19, 2017	November 6, 2017	November 14, 2017	$ 0.3900	$ 47,000	$ 81
January 23, 2018	February 6, 2018	February 14, 2018	$ 0.3900	$ 47,223	$ 81
April 24, 2018	May 7, 2018	May 15, 2018	$ 0.3900	$ 47,374	$ 82
July 24, 2018	August 8, 2018	August 14, 2018	$ 0.3900	$ 47,600	$ 82
October 23, 2018	November 8, 2018	November 14, 2018	$ 0.3900	$ 48,260	$ 83
January 22, 2019	February 6, 2019	February 14, 2019	$ 0.3900	$ 48,373	$ 83
April 24, 2019	May 7, 2019	May 15, 2019	$ 0.3900	$ 49,127	$ 85

Class A Convertible Preferred Units

On April 21, 2016, we entered into a private placement agreement to issue $200 million of 10.75% Class A Convertible Preferred Units (“Class A Preferred Units”) to Oaktree Capital Management L.P. and its co-investors (“Oaktree”). On June 23, 2016, the private placement agreement was amended to increase the aggregate principal amount from $200 million to $240 million. We received net proceeds of $235.0 million (net of offering costs of $5.0 million) in connection with the issuance of 19,942,169 Class A Preferred Units and 4,375,112 warrants.

We pay a cumulative, quarterly distribution in arrears at an annual rate of 10.75% on the Class A Preferred Units to the extent declared by the board of directors of our general partner. To the extent declared, such distributions will be paid for each such quarter within 45 days after each quarter end.

The following table summarizes distributions declared on our Class A Preferred Units during the last three fiscal years:

Date Declared	Payment Date	Amount Paid to Class A Preferred Unitholders
		(in thousands)
July 21, 2016	August 12, 2016	$ 1,795
October 20, 2016	November 14, 2016	$ 6,449
January 19, 2017	February 14, 2017	$ 6,449
April 24, 2017	May 15, 2017	$ 6,449
July 20, 2017	August 14, 2017	$ 6,449
October 19, 2017	November 14, 2017	$ 6,449
January 23, 2018	February 14, 2018	$ 6,449
April 24, 2018	May 15, 2018	$ 6,449
July 24, 2018	August 14, 2018	$ 6,449
October 23, 2018	November 14, 2018	$ 6,449
January 22, 2019	February 14, 2019	$ 6,449
April 24, 2019	May 10, 2019	$ 4,034

If the Class A Preferred Unit quarterly distribution is not made in full in cash for any quarter, the Class A Preferred Unit distribution rate will increase by one quarter of a percentage point (0.25%) per year beginning with distributions for the first six-month period that a payment default is in effect, and will further increase by an additional one quarter of a percentage point (0.25%) beginning with distributions for the next six-month period during which a payment default remains in effect. The deficiency rate shall not exceed 11.25% per year; as long as the default is occurring, the amount of accrued but unpaid Class A Preferred Unit quarterly distributions shall increase at an annual rate of 10.75%, compounded quarterly, until paid in full.

The Class A Preferred Units have no mandatory redemption date but are redeemable, at our election, any time after the first anniversary of the closing date. We have the right to redeem all of the outstanding Class A Preferred Units at a price per Class A Preferred Unit equal to the purchase price multiplied by the redemption multiple then in effect. The redemption multiple means (a) 140% for redemptions occurring on or after the first, but prior to the second anniversary of the closing date, (b) 115% for redemptions occurring on or after the second, but prior to the third anniversary of the closing date, (c) 110% for redemptions occurring on or after the third, but prior to the eighth anniversary of the closing date and (d) 101% for redemptions occurring on or after the eighth anniversary of the closing date.

At any time after the third anniversary of the initial closing date, the Class A preferred unitholders shall have the right to convert all of the outstanding Class A Preferred Units at a price per Class A Preferred Unit equal to the purchase price multiplied by the conversion multiple then in effect, which may be settled in common units, cash or a combination, at our discretion. The conversion multiple means if our common units are trading at or above $12.035 (“the initial conversion price”), the conversion price is not adjusted. However, if the conversion price is less than the initial conversion price, the conversion price will be reset to the greater of (i) the adjusted volume weighted average price of our common units for the 15 trading days immediately preceding the third anniversary of the closing date or (ii) $5.00.

Upon a change of control of the Partnership, each Class A preferred unitholder shall have the right, at its election, to either (i) elect to have its Class A Preferred Units converted to common units; (ii) if we are the surviving entity of such change of control, it can elect to continue to hold its Class A Preferred Units; or (iii) require us to redeem its Class A Preferred Units for cash equal to (a) prior to the first anniversary of the closing date, 140% of the unit purchase price; (b) on or after the first but prior to the second anniversary of the closing date, 130% of the unit purchase price; (c) on or after the second anniversary of the closing date, 120% of the unit purchase price; and (d) thereafter, 101% of the unit purchase price. In each case, this amount will include any accrued but unpaid distributions at the redemption date.

Under the private placement agreement, we are required to file within 180 days of the initial closing date a registration statement registering the resales of common units issued or to be issued upon conversion of the Class A Preferred Units or exercise of the warrants and have the registration statement declared effective within 360 days after the closing date. We are required to continue to maintain the effectiveness of the registration statement until all securities have been sold. The Partnership’s registration statement was declared effective by the SEC on November 23, 2016.

The warrants have an eight year term, after which unexercised warrants will expire. The holders of the warrants may exercise one-third of the warrants from and after the first anniversary of the original issue date, another one-third of the warrants from and after the second anniversary and the final one-third of the warrants from and after the third anniversary. Upon a change of control or in the event we exercise our redemption right with respect to the Class A Preferred Units, all unvested warrants shall immediately vest and be exercisable in full. The warrants have an exercise price of $0.01. During the year ended March 31, 2019, 228,797 warrants were exercised for common units and we received proceeds of less than $0.1 million, and we repurchased 1,229,575 unvested warrants for a total purchase price of $15.0 million on April 26, 2018. During the year ended March 31, 2018, 607,653 warrants were exercised for common units and we received proceeds of less than $0.1 million, and we repurchased 850,716 unvested warrants for a total purchase price of $10.5 million on June 23, 2017. As of March 31, 2019, we had 1,458,371 warrants that remain outstanding, which were all exercised for common units on April 5, 2019 (see below for a further discussion).

We allocated the net proceeds on a relative fair value basis to the Class A Preferred Units ($186.4 million), which includes the value of a beneficial conversion feature, and warrants ($48.6 million). As discussed below, $131.5 million of the amount allocated to the Class A Preferred Units was allocated to the intrinsic value of the beneficial conversion feature. A beneficial conversion feature is defined as a nondetachable conversion feature that is in the money at the commitment date. Per the applicable accounting guidance, we are required to allocate a portion of the proceeds allocated to the Class A Preferred Units to the beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per unit value of our common units at the issuance date) and the proceeds attributed to the Class A Preferred Units. We record the accretion attributable to the beneficial conversion feature as a deemed distribution using the effective interest method over the three year period prior to the effective dates of the holders’ conversion right. Accretion for the beneficial conversion feature was $67.2 million, $18.8 million and $9.0 million for the years ended March 31, 2019, 2018 and 2017, respectively.

As discussed above, the Class A Preferred Units are not mandatorily redeemable but are redeemable upon a change of control, which was not certain to occur at the issuance of the Class A Preferred Units. Due to the redemption being conditioned upon an event that is not certain to occur or that is not under our control, we are required to record the value allocated to the Class A Preferred Units, excluding the value of the beneficial conversion feature, between liabilities and equity (mezzanine or temporary equity) in our consolidated balance sheet. The value allocated to the warrants and the beneficial conversion feature was recorded within limited partners' equity in our consolidated balance sheet.

On April 5, 2019, we made a partial redemption of 7,468,978 of the Class A Preferred Units. The applicable Class A redemption premium on the date of redemption was $13.389, calculated at 111.25% of $12.035 (the Class A Preferred Unit price), and the accrued but unpaid and accumulated distributions of $0.338. The amount per Class A Preferred Unit paid to each Class A preferred unitholder was $13.727, for a total payment of $102.5 million. On April 5, 2019, Oaktree also exercised all of its 1,458,371 warrants to purchase common units for proceeds of less than $0.1 million.

On May 11, 2019, we redeemed the remaining 12,473,191 outstanding Class A Preferred Units. The applicable Class A redemption premium on the date of redemption was $13.2385, calculated at 110% of $12.035 (the Class A Preferred Unit price), and the accrued but unpaid and accumulated distributions of $0.1437. The amount per Class A Preferred Unit paid to each Class A preferred unitholder was $13.3822, for a total payment of $166.9 million. In addition, we paid the Class A preferred unitholders the distribution declared for the quarter ended March 31, 2019, as noted above.

Class B Preferred Units

On June 13, 2017, we issued 8,400,000 of our 9.00% Class B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Class B Preferred Units") representing limited partner interests at a price of $25.00 per unit for net proceeds of $202.7 million (net of the underwriters' discount of $6.6 million and offering costs of $0.7 million).

At any time on or after July 1, 2022, we may redeem our Class B Preferred Units, in whole or in part, at a redemption price of $25.00 per Class B Preferred Unit plus an amount equal to all accumulated and unpaid distributions to, but not including, the date of redemption, whether or not declared. We may also redeem the Class B Preferred Units upon a change of control as defined in our partnership agreement. If we choose not to redeem the Class B Preferred Units, the Class B preferred unitholders may have the ability to convert the Class B Preferred Units to common units at the then applicable conversion rate. Class B preferred unitholders have no voting rights except with respect to certain matters set forth in our partnership agreement.

Distributions on the Class B Preferred Units are payable on the 15th day of each January, April, July and October of each year to holders of record on the first day of each payment month. The initial distribution rate for the Class B Preferred Units from and including the date of original issue to, but not including, July 1, 2022 is 9.00% per year of the $25.00 liquidation preference per unit (equal to $2.25 per unit per year). On and after July 1, 2022, distributions on the Class B Preferred Units will accumulate at a percentage of the $25.00 liquidation preference equal to the applicable three-month LIBOR plus a spread of 7.213%.

The following table summarizes distributions declared on our Class B Preferred Units during the last two fiscal years:

Date Declared	Record Date	Payment Date	Amount Paid to Class B Preferred Unitholders
			(in thousands)
September 18, 2017	September 29, 2017	October 16, 2017	$ 5,670
December 19, 2017	December 29, 2017	January 15, 2018	$ 4,725
March 19, 2018	April 2, 2018	April 16, 2018	$ 4,725
June 19, 2018	July 2, 2018	July 16, 2018	$ 4,725
September 12, 2018	October 1, 2018	October 15, 2018	$ 4,725
December 17, 2018	December 31, 2018	January 15, 2019	$ 4,725
March 15, 2019	April 1, 2019	April 15, 2019	$ 4,725

The distribution amount paid on April 15, 2019 is included in accrued expenses and other payables in our consolidated balance sheet at March 31, 2019.

Class C Preferred Units

On April 2, 2019, we issued 1,800,000 of our 9.625% Class C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Class C Preferred Units") representing limited partner interests at a price of $25.00 per unit for net proceeds of $43.1 million (net of the underwriters' discount of $1.4 million and estimated offering costs of $0.5 million).

At any time on or after April 15, 2024, we may redeem our Class C Preferred Units, in whole or in part, at a redemption price of $25.00 per Class C Preferred Unit plus an amount equal to all accumulated and unpaid distributions to, but not including, the date of redemption, whether or not declared. We may also redeem the Class C Preferred Units upon a change of control as defined in our partnership agreement. If we choose not to redeem the Class C Preferred Units, the Class C preferred unitholders may have the ability to convert the Class C Preferred Units to common units at the then applicable conversion rate. Class C preferred unitholders have no voting rights except with respect to certain matters set forth in our partnership agreement.

Distributions on the Class C Preferred Units are payable on the 15th day of each January, April, July and October of each year to holders of record on the first day of each payment month. The initial distribution rate for the Class C Preferred Units from and including the date of original issue to, but not including, April 15, 2024, is 9.625% per year of the $25.00 liquidation preference per unit (equal to $2.41 per unit per year). On and after April 15, 2024, distributions on the Class C Preferred Units will accumulate at a percentage of the $25.00 liquidation preference equal to the applicable three-month LIBOR plus a spread of 7.384%.

Amended and Restated Partnership Agreement

On April 2, 2019, NGL Energy Holdings LLC executed the Fifth Amended and Restated Agreement of Limited Partnership. The preferences, rights, powers and duties of holders of the Class C Preferred Units are defined in the amended and restated partnership agreement. The Class C Preferred Units rank senior to the common units, with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up, and are on parity with the Class A Preferred Units (see above discussion regarding the redemption of these units) and Class B Preferred Units. The Class C Preferred Units have no stated maturity but we may redeem the Class C Preferred Units at any time on or after April 15, 2024 or upon the occurrence of a change in control.

On June 13, 2017, NGL Energy Holdings LLC executed the Fourth Amended and Restated Agreement of Limited Partnership. The preferences, rights, powers and duties of holders of the Class B Preferred Units are defined in the amended and restated partnership agreement. The Class B Preferred Units rank senior to the common units, with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up, and are on parity with the Class A Preferred Units (see above discussion regarding the redemption of these units). The Class B Preferred Units have no stated maturity but we may redeem the Class B Preferred Units at any time on or after July 1, 2022 or upon the occurrence of a change in control.

On June 24, 2016, NGL Energy Holdings LLC executed the Third Amended and Restated Agreement of Limited Partnership. The preferences, rights, powers and duties of holders of the Class A Preferred Units are defined in the amended and restated partnership agreement. The Class A Preferred Units rank senior to the common units, with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up. The Class A Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless redeemed by the Partnership or converted into common units at the election of the Partnership or the Class A preferred unitholders or in connection with a change of control. See above for a discussion regarding the redemption of the Class A Preferred Units.

Equity-Based Incentive Compensation

Our general partner has adopted a long-term incentive plan ("LTIP"), which allows for the issuance of equity-based compensation. Our general partner has granted certain restricted units to employees and directors , which vest in tranches, subject to the continued service of the recipients. The awards may also vest upon a change of control, at the discretion of the board of directors of our general partner. No distributions accrue to or are paid on the restricted units during the vesting period.

The restricted units include awards that vest contingent on the continued service of the recipients through the vesting date (the "Service Awards").

On April 1, 2017, we made an accounting policy election to account for actual forfeitures, rather than estimate forfeitures each period (as previously required). As a result, the cumulative effect adjustment, which represents the differential between the amount of compensation expense previously recorded and the amount that would have been recorded without assuming forfeitures, had no impact on our consolidated financial statements.

The following table summarizes the Service Award activity during the years ended March 31, 2019, 2018 and 2017:

Unvested Service Award units at March 31, 2016	2,297,132
Units granted	3,124,600
Units vested and issued	(2,350,082)
Units forfeited	(363,150)
Unvested Service Award units at March 31, 2017	2,708,500
Units granted	1,964,911
Units vested and issued	(2,260,011)
Units forfeited	(134,525)
Unvested Service Award units at March 31, 2018	2,278,875
Units granted	3,141,993
Units vested and issued	(2,833,968)
Units forfeited	(278,500)
Unvested Service Award units at March 31, 2019	2,308,400

In connection with the vesting of certain restricted units during the year ended March 31, 2019, we canceled 26,993 of the newly-vested common units in satisfaction of $0.3 million of employee tax liability paid by us. Pursuant to the terms of the LTIP, these canceled units are available for future grants under the LTIP.

The following table summarizes the scheduled vesting of our unvested Service Award units at March 31, 2019:

Year Ending March 31,	Number of Units
2020	1,005,725
2021	869,425
2022	433,250
Total	2,308,400

Service Awards are valued at the average of the high/low sales price as of the grant date less the present value of the expected distribution stream over the vesting period using a risk-free interest rate. We record the expense for each Service Award on a straight-line basis over the requisite period for the entire award (that is, over the requisite service period of the last separately vesting portion of the award), ensuring that the amount of compensation cost recognized at any date at least equals the portion of the grant-date value of the award that is vested at that date.

During the years ended March 31, 2019, 2018 and 2017, we recorded compensation expense related to Service Award units of $12.0 million, $16.2 million and $56.2 million, respectively.

Of the restricted units granted and vested during the year ended March 31, 2019, 1,745,801 units were granted as a bonus for performance during the year ended March 31, 2018. The total amount of these bonus payments was $20.4 million, of which we had accrued $6.3 million as of March 31, 2018. Also, 59,393 units were granted and vested as incentive compensation for the year ended March 31, 2018. The value of these awards was $0.7 million and was recorded within general and administrative expense in our consolidated statement of operations for the year ended March 31, 2018.

Of the restricted units granted and vested during the year ended March 31, 2019, 176,817 units were granted as a bonus for performance during the year ended March 31, 2019. The total amount of these bonus payments was $2.4 million.

Of the restricted units granted and vested during the year ended March 31, 2017, 1,008,091 units were granted as a bonus for performance during the year ended March 31, 2016. We accrued expense of $16.8 million during the year ended March 31, 2016 as an estimate of the value of such bonus units that would be granted. During the year ended March 31, 2017, we recorded an additional $2.2 million to true up the estimate to the $19.0 million of actual expense associated with these bonuses. Since the units were not granted until August 2016, the full $19.0 million is reflected in the expense during the year ended March 31, 2017.

The following table summarizes the estimated future expense we expect to record on the unvested Service Award units at March 31, 2019 (in thousands):

Year Ending March 31,		
2020	$	8,168
2021		4,154
2022		1,350
Total	$	13,672

Beginning in April 2015, our general partner granted units that vest contingent both on the continued service of the recipients through the vesting date and also on the performance of our common units relative to other entities in the Alerian MLP Index (the “Index”) over specified periods of time (the “Performance Awards”). These Performance Award units were granted to certain employees. Performance was to be calculated based on the return on our common units (including changes in the market price of the common units and distributions paid during the performance period) relative to the returns on the common units of the other entities in the Index. During the three months ended December 31, 2018, the compensation committee of the board of directors of our general partner terminated the Performance Award plan and all unvested outstanding Performance Awards units were canceled. Accordingly, as no replacement awards were granted, all previously unrecognized compensation cost was expensed as of the cancellation date. During the year ended March 31, 2019, we recorded compensation expense related to the cancellation of the Performance units of $3.1 million which was recorded within general and administrative expense in our consolidated statement of operations for the year ended March 31, 2019.

The following table summarizes the Performance Award activity during the years ended March 31, 2019, 2018 and 2017:

Unvested Performance Award units at March 31, 2016	637,382
Units granted	932,309
Units forfeited	(380,691)
Unvested Performance Award units at March 31, 2017	1,189,000
Units granted	224,000
Units forfeited	(496,000)
Unvested Performance Award units at March 31, 2018	917,000
Units forfeited	(445,500)
Units canceled	(471,500)
Unvested Performance Award units at March 31, 2019	—

During the July 1, 2015 through June 30, 2018 performance period, the return on our common units was below the return of the 50th percentile of our peer companies in the Index. As a result, no Performance Award units vested on July 1, 2018 and performance units with the July 1, 2018 vesting date are considered to be forfeited.

The fair value of the Performance Awards is estimated using a Monte Carlo simulation at the grant date. The significant inputs used to calculate the fair value of these awards include (i) the price per our common units at the grant date and the beginning of the performance period, (ii) a compounded risk-free interest rate, (iii) our compounded dividend yield, (iv) our historical volatility, (v) the volatility and correlations of our peers and (vi) the remaining performance period. We recorded the expense on a straight-line basis over the period beginning with the grant date and ending with the vesting date of the tranche. Any Performance Awards not earned at the end of the performance period will terminate, expire and otherwise be forfeited by the participants. During the years ended March 31, 2019, 2018 and 2017, we recorded compensation expense related to Performance Award units of $4.9 million (including amounts recorded related to the cancellation of the Performance Award plan (see above)), $5.3 million and $7.2 million, respectively.

The number of common units that may be delivered pursuant to awards under the LTIP is limited to 10% of our issued and outstanding common units. The maximum number of common units deliverable under the LTIP automatically increases to 10% of the issued and outstanding common units immediately after each issuance of common units, unless the plan administrator determines to increase the maximum number of units deliverable by a lesser amount. When an award is forfeited, canceled, exercised, paid or otherwise terminates or expires without the delivery of units, the units subject to such award are again available for new awards under the LTIP. The LTIP provides that units allocated to satisfy tax withholding obligations are not deemed to reduce availability for awards under the LTIP. Following a review of the LTIP, the compensation committee of the board of directors of our general partner determined that units vested after July 1, 2016 were inadvertently counted as a reduction to the Partnership's LTIP reserve. Accordingly, after making the adjustments as provided for in the LTIP, as of March 31, 2019, there are approximately 3.3 million units remaining available for issuance under the LTIP.

Note 11—Fair Value of Financial Instruments

Our cash and cash equivalents, accounts receivable, accounts payable, accrued expenses, and other current assets and liabilities (excluding derivative instruments) are carried at amounts which reasonably approximate their fair values due to their short-term nature.

Commodity Derivatives

The following table summarizes the estimated fair values of our commodity derivative assets and liabilities reported in our consolidated balance sheet at the dates indicated:

	March 31, 2019		March 31, 2018	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
	(in thousands)			
Level 1 measurements	$ 49,509	$ (7,273)	$ 5,093	$ (20,186)
Level 2 measurements	86,785	(100,564)	48,752	(54,410)
	136,294	(107,837)	53,845	(74,596)
Netting of counterparty contracts (1)	(7,501)	7,501	(2,922)	2,922
Net cash collateral (held) provided	(18,271)	(208)	(1,762)	17,263
Commodity derivatives	$ 110,522	$ (100,544)	$ 49,161	$ (54,411)

(1) Relates to commodity derivative assets and liabilities that are expected to be net settled on an exchange or through a netting arrangement with the counterparty. Our physical contracts that do not qualify as normal purchase normal sale transactions are not subject to such netting arrangements.

The following table summarizes the accounts that include our commodity derivative assets and liabilities in our consolidated balance sheets at the dates indicated:

	March 31,	
	2019	2018
	(in thousands)	
Prepaid expenses and other current assets	$ 110,521	$ 49,161
Other noncurrent assets	1	—
Accrued expenses and other payables	(100,372)	(51,039)
Other noncurrent liabilities	(172)	(3,372)
Net commodity derivative asset (liability)	$ 9,978	$ (5,250)

The following table summarizes our open commodity derivative contract positions at the dates indicated. We do not account for these derivatives as hedges.

Contracts	Settlement Period	Net Long (Short) Notional Units (in barrels)	Fair Value of Net Assets (Liabilities)
		(in thousands)	
At March 31, 2019:			
Crude oil fixed-price (1)	April 2019–December 2020	(1,961)	1,014
Propane fixed-price (1)	April 2019–March 2020	198	608
Refined products fixed-price (1)	April 2019–January 2021	(2,296)	22,079
Other	April 2019–March 2022		4,756
			28,457
Net cash collateral held			(18,479)
Net commodity derivative asset			$ 9,978
At March 31, 2018:			
Cross-commodity (2)	April 2018–March 2019	155	$ (430)
Crude oil fixed-price (1)	April 2018–December 2019	(1,376)	$ (8,960)
Crude oil index (1)	April 2018–April 2018	(10)	$ (6)
Propane fixed-price (1)	April 2018–February 2019	14	1,849
Refined products fixed-price (1)	April 2018–January 2020	(5,419)	(17,081)
Refined products index (1)	April 2018–April 2018	(4)	(17)
Other	April 2018–March 2022		3,894
			(20,751)
Net cash collateral provided			15,501
Net commodity derivative liability			$ (5,250)

(1) We may have fixed price physical purchases, including inventory, offset by floating price physical sales or floating price physical purchases offset by fixed price physical sales. These contracts are derivatives we have entered into as an economic hedge against the risk of mismatches between fixed and floating price physical obligations.

(2) We may purchase or sell a physical commodity where the underlying contract pricing mechanisms are tied to different commodity price indices. These contracts are derivatives we have entered into as an economic hedge against the risk of one commodity price moving relative to another commodity price.

Amounts in the table above do not include commodity derivative contract positions related to our former Retail Propane segment, as these amounts have been classified as assets held for sale within our March 31, 2018 consolidated balance sheet (see Note 17).

The following table summarizes the net gains (losses) recorded from our commodity derivatives to revenues and cost of sales in our consolidated statements of operations for the periods indicated (in thousands):

Year Ended March 31,	
2019	$ 33,631
2018	$ (116,604)
2017	$ (55,978)

Amounts in the table above do not include net losses from our commodity derivatives related to our former Retail Propane segment, as these amounts have been classified within discontinued operations within our consolidated statements of operations (see Note 17).

Credit Risk

We have credit policies that we believe minimize our overall credit risk, including an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, and the use of industry standard master netting agreements, which allow for offsetting counterparty receivable and payable balances for certain transactions. At March 31, 2019, our primary counterparties were retailers, resellers, energy marketers, producers, refiners, and dealers. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, as the counterparties may be similarly affected by changes in economic, regulatory or other conditions. If a counterparty does not perform on a contract, we may not realize amounts that have been recorded in our consolidated balance sheets and recognized in our net income.

Interest Rate Risk

The Revolving Credit Facility is variable-rate debt with interest rates that are generally indexed to bank prime or LIBOR interest rates. At March 31, 2019, we had $1.2 billion of outstanding borrowings under the Revolving Credit Facility at a weighted average interest rate of 4.39%.

Fair Value of Fixed-Rate Notes

The following table provides fair values estimates of our fixed-rate notes at March 31, 2019 (in thousands):

Senior Unsecured Notes:		
2023 Notes	$	626,621
2025 Notes	$	375,126

For the Senior Unsecured Notes, the fair value estimates were developed based on publicly traded quotes and would be classified as Level 1 in the fair value hierarchy.

Note 12—Segments

The following table summarizes revenues related to our segments. Revenues for reporting periods beginning after April 1, 2018 are presented under Topic 606 (see Note 15 for a further discussion), while prior periods are not adjusted and continue to be reported under the accounting standard in effect for those periods. Transactions between segments are recorded based on prices negotiated between the segments. The "Corporate and Other" category in the table below includes certain corporate expenses that are not allocated to the reportable segments. The table below does not include amounts related to our former Retail Propane segment, as these amounts have been classified within discontinued operations within our consolidated statements of operations (see Note 17).

	Year Ended March 31,		
	2019	2018 (1)	2017 (1)
		(in thousands)	
Revenues:			
Crude Oil Logistics:			
Topic 606 revenues			
Crude oil sales	$ 3,011,355	$ 2,151,203	$ 1,603,667
Crude oil transportation and other	148,738	122,786	70,027
Non-Topic 606 revenues	12,598	—	—
Elimination of intersegment sales	(36,056)	(13,914)	(6,810)
Total Crude Oil Logistics revenues	3,136,635	2,260,075	1,666,884
Water Solutions:			
Topic 606 revenues			
Disposal service fees	217,545	149,114	110,049
Sale of recovered hydrocarbons	72,678	58,948	31,103
Freshwater revenues	2,404	—	—
Other service revenues	9,017	21,077	18,449
Non-Topic 606 revenues	42	—	—
Total Water Solutions revenues	301,686	229,139	159,601
Liquids:			
Topic 606 revenues			
Propane sales	1,169,117	1,203,486	807,172
Butane sales	628,063	562,066	391,265
Other product sales	592,889	432,570	308,031
Service revenues	26,655	22,548	32,648
Non-Topic 606 revenues	21,608	—	—
Elimination of intersegment sales	(23,291)	(4,685)	(1,944)
Total Liquids revenues	2,415,041	2,215,985	1,537,172
Refined Products and Renewables:			
Topic 606 revenues			
Refined products sales	5,455,204	11,827,222	8,884,976
Renewables sales	—	373,669	447,232
Service fees and other revenues	498	300	10,963
Non-Topic 606 revenues	12,706,481	—	—
Elimination of intersegment sales	—	(268)	(469)
Total Refined Products and Renewables revenues	18,162,183	12,200,923	9,342,702
Corporate and Other			
Non-Topic 606 revenues	1,362	1,174	844
Total Corporate and Other revenues	1,362	1,174	844
Total revenues	$ 24,016,907	$ 16,907,296	$ 12,707,203

(1) We adopted ASC 606 as of April 1, 2018. Revenue reported in fiscal years 2018 and 2017 has not been changed from its previous presentation.

The following table summarizes depreciation and amortization expense and operating income (loss) by segment for the periods indicated.

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Depreciation and Amortization:			
Crude Oil Logistics	$ 74,165	$ 80,387	$ 54,144
Water Solutions	108,162	98,623	101,758
Liquids	25,997	24,937	19,163
Refined Products and Renewables	1,518	1,294	1,562
Corporate and Other	3,018	3,779	3,612
Total depreciation and amortization (1)	$ 212,860	$ 209,020	$ 180,239
Operating Income (Loss):			
Crude Oil Logistics	$ (7,379)	$ 122,904	$ (17,475)
Water Solutions	210,525	(24,231)	44,587
Liquids	(2,910)	(93,113)	43,252
Refined Products and Renewables	27,459	56,740	222,546
Corporate and Other	(85,706)	(79,474)	(86,985)
Total operating income (loss)	$ 141,989	$ (17,174)	$ 205,925

(1) Amounts do not include amortization expense recorded within interest expense and cost of sales (see Note 7 and Note 8).

The following table summarizes additions to property, plant and equipment and intangible assets by segment for the periods indicated. This information has been prepared on the accrual basis, and includes property, plant and equipment and intangible assets acquired in acquisitions. This information below does not include goodwill by segment.

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Crude Oil Logistics	$ 28,039	$ 36,762	$ 168,053
Water Solutions	567,637	102,261	109,008
Liquids	72,717	25,023	66,864
Refined Products and Renewables	14,613	—	42,175
Corporate and Other	1,819	1,472	2,825
Total	$ 684,825	$ 165,518	$ 388,925

The following tables summarize long-lived assets (consisting of property, plant and equipment, intangible assets, and goodwill) and total assets by segment at the dates indicated:

	March 31,	
	2019	2018
	(in thousands)	
Long-lived assets, net:		
Crude Oil Logistics	$ 1,584,636	$ 1,638,558
Water Solutions	1,600,836	1,256,143
Liquids (1)	498,767	501,302
Refined Products and Renewables	217,881	208,849
Corporate and Other	26,569	31,516
Total	$ 3,928,689	$ 3,636,368

(1) Includes $0.5 million and $0.6 million of non-US long-lived assets at March 31, 2019 and 2018, respectively.

	March 31,	
	2019	2018
	(in thousands)	
Total assets:		
Crude Oil Logistics	$ 2,237,612	$ 2,285,813
Water Solutions	1,668,292	1,323,171
Liquids (1)	721,008	717,690
Refined Products and Renewables	1,198,562	1,204,633
Corporate and Other	77,019	102,211
Assets held for sale	—	517,604
Total	$ 5,902,493	$ 6,151,122

(1) Includes $12.0 million and $27.5 million of non-US total assets at March 31, 2019 and 2018, respectively.

Note 13—Transactions with Affiliates

A member of the board of directors of our general partner is an executive officer of WPX Energy, Inc. (“WPX”). We purchase crude oil from and sell crude oil to WPX (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). We also treat and dispose of wastewater and solids received from WPX.

SemGroup Corporation (“SemGroup”) holds ownership interests in our general partner. We sell product to and purchase product from SemGroup, and these transactions are included within revenues and cost of sales, respectively, in our consolidated statements of operations. We also lease crude oil storage from SemGroup.

We purchased ethanol from E Energy Adams, LLC, in which we previously held an ownership interest as an equity method investee. We sold our interest in E Energy Adams, LLC on May 3, 2018 (see Note 2). These transactions are reported within cost of sales in our consolidated statements of operations.

The following table summarizes these related party transactions for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Sales to WPX	$ 28,026	$ —	$ —
Purchases from WPX (1)	$ 329,525	$ —	$ —
Sales to SemGroup	$ 1,114	$ 606	$ 3,866
Purchases from SemGroup	$ 4,395	$ 5,034	$ 12,254
Sales to entities affiliated with management	$ 21,385	$ 268	$ 290
Purchases from entities affiliated with management	$ 4,382	$ 3,870	$ 15,209
Sales to equity method investees	$ —	$ 294	$ 692
Purchases from equity method investees	$ —	$ 66,820	$ 121,336

(1) Amount primarily relates to purchases of crude oil under the definitive agreement we signed with WPX, as discussed further below.

Accounts receivable from affiliates consist of the following at the dates indicated:

	March 31, 2019	March 31, 2018
	(in thousands)	
Receivables from NGL Energy Holdings LLC	$ 7,277	$ 4,693
Receivables from WPX	5,185	—
Receivables from SemGroup	71	49
Receivables from entities affiliated with management	334	24
Receivables from equity method investees	—	6
Total	$ 12,867	$ 4,772

Accounts payable to affiliates consist of the following at the dates indicated:

	March 31, 2019	March 31, 2018
	(in thousands)	
Payables to WPX	$ 27,844	$ —
Payables to entities affiliated with management	625	1,246
Payables to equity method investees	—	8
Total	$ 28,469	$ 1,254

Other Related Party Transactions

Victory Propane

On August 14, 2018, we sold our 50% interest in Victory Propane to Victory Propane, LLC. As consideration, we received a promissory note in the amount of $3.4 million, which encompassed the purchase price for our 50% interest plus the outstanding balance of the loan receivable of $2.6 million as of the date of the transaction. The promissory note bears no interest and matures on July 31, 2023. We discounted the promissory note to its net present value of $2.6 million, with the amount of the reduction in the value of the promissory note recorded as a loss within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations. This was the final transaction in exiting the retail propane business and was considered to be inconsequential by management. As a result of the sale, Victory Propane is no longer considered a related party.

At March 31, 2018, we had a loan receivable from Victory Propane, an equity method investee at the time (see Note 2), of $1.2 million.

During the three months ended December 31, 2017 we completed a transaction with Victory Propane, an equity method investee at the time (See Note 2), to purchase Victory Propane's Michigan assets. We paid Victory Propane $6.4 million in cash and received current assets, property, plant and equipment and customers. The allocation of the consideration was as follows (in thousands):

Current assets	$ 276
Property, plant and equipment	1,366
Intangible assets (customer relationships)	4,782
Fair value of net assets acquired	$ 6,424

Victory Propane recognized a gain on this transaction. As all intra-entity profits and losses are eliminated between an investor and investee until realized, we eliminated our proportionate share of the gain from this transaction on our books. As a result, our underlying equity in the net assets of Victory Propane exceeded our investment (see Note 2), and this difference was amortized as income over the remaining life of the noncurrent assets acquired until they were sold on August 14, 2018. As the sale of virtually all of our remaining Retail Propane segment to Superior (see Note 1) included Victory Propane's Michigan assets, we were able to recognize our proportionate share of the gain recognized by Victory Propane. As a result, we were able to reverse our proportionate share of their losses that had been recorded against the balance of the loan receivable and write up the value of our investment in Victory Propane to $0.8 million.

Agreement with WPX

During the three months ended June 30, 2018, we entered into a definitive agreement with WPX. Under this agreement, we agreed to provide WPX the benefit of our minimum shipping fees or deficiency credits (fees paid in previous periods that were in excess of the volumes actually shipped) totaling $67.7 million at the time of the transaction (as discussed further in Note 2), which can be utilized for volumes shipped that exceed the minimum monthly volume commitment in subsequent periods. As a result, we wrote-off these minimum shipping fees previously included within other noncurrent assets in our consolidated balance sheet (see Note 2) and recorded a loss within loss (gain) on disposal or impairment of assets, net . We also agreed that we would only ship crude oil that we are required to purchase from WPX in utilizing our allotted capacity on these pipelines and they agreed to be fully responsible to us for all deficiency payments (money due when our actual shipments are less than our allotted capacity) for the remaining term of our contract, which totaled $50.3 million at June 30, 2018 (as discussed further in Note 9). As consideration for this transaction, we paid WPX a net $35.3 million, which was recorded as a loss within loss (gain) on disposal or impairment of assets, net .

Repurchase of Warrants

On April 26, 2018 and June 23, 2017, we repurchased outstanding warrants, as discussed further in Note 10, from funds managed by Oaktree, who were represented on the board of directors of our general partner (see Note 19).

Grassland

We previously had a loan receivable from Grassland Water Solutions, LLC (“Grassland”) and during the three months ended June 30, 2016, we received loan payments of $0.7 million from Grassland in accordance with the loan agreement. On June 3, 2016, we acquired the remaining 65% ownership interest in Grassland. Prior to the completion of this transaction, we accounted for our previously held 35% ownership interest in Grassland using the equity method of accounting. As we owned a controlling interest in Grassland, we revalued our previously held 35% ownership interest to fair value of $0.8 million and recorded a loss of $14.9 million. As the amount paid (cash plus the fair value of our previously held ownership interest) was less than the fair value of the assets acquired and liabilities assumed, we recorded a bargain purchase gain of $0.6 million. Once we acquired the remaining ownership interest in Grassland, the loan receivable was eliminated as Grassland was consolidated in our consolidated financial statements. As a result of the acquisition, we incurred an impairment charge of $1.7 million to write down the loan receivable to its fair value, which was reported within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations. On November 29, 2016, we sold Grassland and received proceeds of $22.0 million and recorded a loss on disposal of $2.3 million during the three months ended December 31, 2016. This loss is reported within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations.

Note 14—Employee Benefit Plan

We have established a defined contribution 401(k) plan to assist our eligible employees in saving for retirement on a tax-deferred basis. The 401(k) plan permits all eligible employees to make voluntary pre-tax contributions to the plan, subject to applicable tax limitations. For every dollar that employees contribute up to 1% of their eligible compensation (as defined in the plan), we contribute one dollar, plus 50 cents for every dollar employees contribute between 1% and 6% of their eligible compensation (as defined in the plan). Our matching contributions prior to January 1, 2015 vest over five years and, effective January 1, 2015, our matching contributions vest over two years. Expenses under the plan for the years ended March 31, 2019, 2018 and 2017 were $2.0 million, $1.8 million and $1.9 million, respectively. Expenses for matching contributions related to our former Retail Propane segment have been classified within discontinued operations within our consolidated statements of operations (see Note 17).

Note 15—Revenue from Contracts with Customers

Impact of Adoption

We adopted ASC 606 on April 1, 2018, using the modified retrospective method. Revenues for reporting periods beginning after April 1, 2018 are presented under Topic 606, while prior periods are not adjusted and continue to be reported under the accounting standard in effect for those periods. We recorded an increase to the beginning balance of equity as of April 1, 2018, due to the cumulative impact of adopting the standard, as discussed further below.

Based on our evaluation, we anticipate that from time to time, differences in the timing of revenues earned and our right to invoice customers may create contract assets or liabilities. These differences in timing would be the result of contracts that contain minimum volume commitments and tiered pricing provisions, primarily within our Water Solutions segment. In addition, we completed the process of implementing appropriate changes to our business processes, systems and controls to support recognition and disclosure under this standard. Furthermore, under this standard we made an accounting policy election to exclude from the measurement of the transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction that we collect from a customer.

As discussed previously, we sold our general partner interest in TransMontaigne Partners L.P. ("TLP") and deferred a portion of the gain related to the sale of which the current portion was recorded in accrued expenses and other payables and the long-term portion was recorded in other noncurrent liabilities at March 31, 2018 within our consolidated balance sheet. During the years ended March 31, 2018 and 2017, we recognized $30.1 million and $30.1 million, respectively, of the deferred gain in our consolidated statements of operations. As this transaction was accounted for under the real estate guidance in ASC 360-20, *Property, Plant and Equipment,* we had been amortizing the gain over the life of the related lease agreements. Upon adoption of ASC 606, we determined that this transaction should be accounted for under the guidance of ASC 810-10-40 and utilizing the modified retrospective approach of adoption, the deferred gain as of March 31, 2018 of $139.3 million was recognized in the beginning balance of retained earnings as part of our cumulative effect adjustment at April 1, 2018.

The following tables summarize the impact of adoption on our consolidated balance sheet at March 31, 2019 and our consolidated statements of operations for the year ended March 31, 2019:

	Consolidated Balance Sheet March 31, 2019		
	As Reported	**Balances Without Adoption of ASC 606**	**Effect of Change Increase/(Decrease)**
		(in thousands)	
Accrued expenses and other liabilities	$ 248,450	$ 278,563	$ (30,113)
Other noncurrent liabilities	$ 63,575	$ 142,656	$ (79,081)
Equity:			
General partner	$ (50,603)	$ (50,712)	$ 109
Limited partners	$ 2,067,197	$ 1,958,113	$ 109,084

	Consolidated Statement of Operations March 31, 2019		
	As Reported	**Balances Without Adoption of ASC 606**	**Effect of Change Increase/(Decrease)**
		(in thousands)	
Loss on disposal or impairment of assets, net	$ 34,296	$ 4,183	$ 30,113
Operating income	$ 141,989	$ 172,102	$ (30,113)
Net income	$ 339,395	$ 369,508	$ (30,113)

Prior to April 1, 2018, we recognized revenue for services and products when all of the following criteria were met under Topic 605: (i) either services have been rendered or products have been delivered or sold; (ii) persuasive evidence of an arrangement existed; (iii) the price for services was fixed or determinable; and (iv) collectibility was reasonably assured. We recorded deferred revenue when we received amounts from our customers but had not yet met the criteria listed above. We recognized deferred revenue in our consolidated statement of operations when the criteria had been met and all services had been rendered.

Effective April 1, 2018, we recognize revenue for services and products under revenue contracts as our obligations to either perform services or deliver or sell products under the contracts are satisfied. A performance obligation is a promise in a contract to transfer a distinct good or service to the customer. A contract's transaction price is allocated to each distinct performance obligation in the contract and is recognized as revenue when, or as, the performance obligation is satisfied. Our revenue contracts in scope under ASC 606 primarily have a single performance obligation. The evaluation of when performance obligations have been satisfied and the transaction price that is allocated to our performance obligations requires significant judgment and assumptions, including our evaluation of the timing of when control of the underlying good or service has transferred to our customers and the relative stand-alone selling price of goods and services provided to customers under contracts with multiple performance obligations. Actual results can vary from those judgments and assumptions. We do not have any material contracts with multiple performance obligations or under which we receive material amounts of non-cash consideration at March 31, 2018. Our costs to obtain or fulfill our revenue contracts were not material as of March 31, 2019.

The majority of our revenue agreements are within scope under ASC 606 and the remainder of our revenue comes from contracts that are accounted for as derivatives under ASC 815 or that contain nonmonetary exchanges or leases and are in scope under Topics 845 and 840, respectively. See Note 12 for a detail of disaggregated revenue. Revenue from contracts accounted for as derivatives under ASC 815 within our Refined and Renewables segment includes $75.5 million of net losses related to changes in the mark-to-market value of these arrangements recorded during the year ended March 31, 2019.

Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30 to 60 days. In instances where the timing of revenue recognition differs from the timing of invoicing, we have determined our contracts generally do not include a significant financing component. The primary purpose of our invoicing terms is to allow customers to secure the right to reserve the product or storage capacity to be received or used at a later date, not to receive financing from our customers or to provide customers with financing.

We report taxes collected from customers and remitted to taxing authorities, such as sales and use taxes, on a net basis. We include amounts billed to customers for shipping and handling costs in revenues in our consolidated statements of operations.

Crude Oil Logistics Performance Obligations

Within the Crude Oil Logistics segment, revenue is disaggregated into two primary revenue streams that include revenue from the sale of commodities and service revenue. For sales of commodities, we are obligated to deliver a predetermined amount of product on a month-to-month basis to our customers. For these types of agreements, revenue is recognized at a point in time based on when the product is delivered and control is transferred to the customer.

For revenue received from services rendered, we are obligated to provide throughput services to move product via pipeline, truck, railcar, or marine vessel or to provide terminal maintenance services. In either case, the obligation is satisfied over time utilizing the output method based on each volume of product that is moved from the origination point to the final destination or based on the passage of time.

Water Solutions Performance Obligations

Within the Water Solutions segment, revenue is disaggregated into two primary revenue streams that include service revenue and commodity sales revenue. For contracts involving disposal services, we accept wastewater and solids for disposal at our facilities. In cases where we have agreed within a contract or are required by law to remove hydrocarbons from the wastewater, the skim oil will be valued as non-cash consideration. Ordinarily, it is required that the fair value of the skim oil is to be estimated at contract inception; however, due to variability of the form of the non-cash consideration, the amount and dollar value is unknown at the contract inception date. Accordingly, ASC 606-10-32-11 allows us to value the skim oil on the date in which the value becomes known.

The Water Solutions segment has certain disposal contracts that contain the following types of terms or pricing structures that involve significant judgment that impacts the determination and timing of revenue.

- *Minimum volume commitments.* We receive a shortfall fee if the customer does not deliver a certain amount of volume of wastewater over a specified period of time. At each reporting period, we make a determination as to the likelihood of earning this fee. We recognize revenue from these contracts when (i) actual volumes are received; and (ii) when the likelihood of a customer exercising its remaining rights to make up the deficient volumes under minimum volume commitments becomes remote (also known as the breakage model).
- *Tiered pricing.* For contracts with tiered pricing provisions, the period in which the tiers are earned and settled (i.e. the “reset period”) may vary from monthly to over a period of multiple months. If the tiered pricing is based on a month, we allocate the fee to the distinct daily service to which it relates. If the tiered pricing spans across multiple reporting periods, we estimate the total transaction price at the beginning of each reset period, based on the expected volumes. We revise our estimates of variable consideration at each reporting date throughout each reset period.
- *Volume discount pricing.* Volume discount pricing is a form of variable consideration whereby the customer pays for the volumes delivered on a cumulative basis. Similar to tiered pricing, the period in which the cumulative volumes are earned and settled (i.e. the “reset period”) may vary from daily to over a period of multiple months. If

the volume discount is based on a month, we allocate the fee to the distinct daily service to which it relates. If the volume discount period spans across multiple reporting periods, we estimate the total transaction price at the beginning of each reset period, based on the expected volumes. We revise the estimate of variable consideration at each reporting date.

For all of our disposal contracts within the Water Solutions segment, revenue will be recognized over time utilizing the output method based on the volume of wastewater or solids we accept from the customer. For contracts that involve the sale of recovered hydrocarbons and freshwater, we will recognize revenue at a point in time, based on when control of the product is transferred to the customer.

Liquids Performance Obligations

Within the Liquids segment, revenue is disaggregated into two primary revenue streams that include revenue from the sale of commodities and providing services. For commodity sales, we are obligated to deliver a specified amount of product over a specified period of time. For these types of agreements, revenue is recognized at a point in time based on when the product is delivered and control is transferred to the customer. For revenue received from services rendered, we offer a variety of services which include: (i) storage services where product is commingled; (ii) railcar transportation services; (iii) transloading services; and (iv) logistics services. We are obligated to provide these services over a predetermined period of time. Revenue from service contracts is recognized at a point in time upon the transfer of control each month. All revenue from services is recognized over time utilizing the output method based on volumes stored or moved.

Refined Products and Renewables Performance Obligations

The Refined Products and Renewables segment has one distinct revenue stream, which is revenue from commodity sales. In these agreements, we are obligated to sell a predetermined amount of product over a specified period of time. Revenue for all commodity sales is recognized at a point in time once the customer has lifted the agreed-upon volumes.

Remaining Performance Obligations

Most of our service contracts are such that we have the right to consideration from a customer in an amount that corresponds directly with the value to the customer of our performance completed to date. Therefore, we are utilizing the practical expedient in ASC 606-10-55-18 under which we recognize revenue in the amount to which we have the right to invoice. Applying this practical expedient, we are not required to disclose the transaction price allocated to remaining performance obligations under these agreements. The following table summarizes the amount and timing of revenue recognition for such contracts at March 31, 2019 (in thousands):

Fiscal Year Ending March 31,	
2020	$ 167,061
2021	128,572
2022	119,016
2023	113,861
2024	99,430
Thereafter	242,032
Total	$ 869,972

Many agreements are short-term in nature with a contract term of one year or less. For those contracts, we utilized the practical expedient in ASC 606-10-50 that exempts us from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. Additionally, for our product sales contracts, we have elected the practical expedient set out in ASC 606-10-50-14A, which states that we are not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these agreements, each unit of product represents a separate performance obligation and therefore future volumes are wholly unsatisfied and disclosure of transaction price allocated to remaining performance obligations is not required. Under product sales contracts, the variability arises as both volume and pricing (typically index-based) are not known until the product is delivered.

Contract Assets and Liabilities

Amounts owed from our customers under our revenue contracts are typically billed as the service is being provided on a monthly basis and are due within 1-30 days of billing, and are classified as accounts receivable-trade on our consolidated balance sheets. Under certain of our contracts, we recognize revenues in excess of billings, referred to as contract assets, within prepaid expenses and other current assets in our consolidated balance sheets. Accounts receivable from contracts with customers are presented within accounts receivable-trade and accounts receivable-affiliates in our consolidated balance sheets. Our contract asset balances primarily relate to our underground cavern storage contracts with multi-period contracts in which the fee escalates each year and the customer provides upfront payment at the beginning of the contract period. We did not record any contract assets during this period.

Under certain of our contracts we may be entitled to receive payments in advance of satisfying our performance obligations under the contract. We recognize a liability for these payments in excess of revenue recognized, referred to as deferred revenue or contract liabilities, within advance payments received from customers in our consolidated balance sheets. Our deferred revenue primarily relates to:

- *Prepayments.* Some revenue contracts contain prepayment provisions within our Liquids segment. Revenue received related to our underground cavern storage services is received upfront at the beginning of the contract period and is deferred until services have been rendered. In some cases, we also receive prepayments from customers purchasing commodities, which allows the customer to secure the right to receive their requested volumes in a future period. Revenue from these contracts is initially deferred, thus creating a contract liability.
- *Multi-period contract in which fee escalates each subsequent year of the contract.* Revenue from these contracts is recognized over time based on a weighted average of what is expected to be received over the life of the contract. As the actual amount billed and received from the customer differs from the amount of revenue recognized, a contract liability is recorded.
- *Tiered pricing and volume discount pricing.* As described above, we revise our estimates of variable consideration at each reporting date throughout each reset period. As the actual amount billed and received from the customer differs from the amount of revenue recognized, a contract liability is recorded.
- *Capital reimbursements.* Certain contracts in our Water Solutions segment require that our customers reimburse us for capital expenditures related to the construction of long-lived assets, such as water gathering pipelines and custody transfer points, utilized to provide services to them under the revenue contracts. Because we consider these amounts as consideration from customers associated with ongoing services to be provided to customers, we defer these upfront payments in deferred revenue and recognize the amounts in revenue over the life of the associated revenue contract as the performance obligations are satisfied under the contract.

The following tables summarizes the balances of our contract assets and liabilities at the dates indicated (in thousands):

	Balance at	
	April 1, 2018	March 31, 2019
Accounts receivable from contracts with customers	$ 677,095	$ 740,878
Contract liabilities balance at April 1, 2018		$ 8,374
Payment received and deferred		77,956
Payment recognized in revenue		(77,409)
Contract liabilities balance at March 31, 2019		$ 8,921

Note 16—Other Matters

Sale of South Pecos Water Disposal Business

On February 28, 2019, we completed the sale of our South Pecos water disposal business to a subsidiary of WaterBridge Resources LLC for $232.2 million in net cash proceeds and recorded a gain on disposal of $107.9 million during the year ended March 31, 2019. This gain is reported within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations. These operations include: (i) nine saltwater disposal facilities, (ii) all disposal agreements, commercial, surface and other contracts related to those facilities, (iii) pipelines connected to the facilities and (iv) several disposal permits. All of the assets sold in this transaction are located near the town of Pecos, Texas in southern Reeves and Ward counties. WaterBridge Resources LLC also has the option to acquire additional land and permits once the permitting process has been completed.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Water Solutions segment have not been classified as discontinued operations.

Sale of Bakken Saltwater Disposal Business

On November 30, 2018, we completed the sale of NGL Water Solutions Bakken, LLC to an affiliate of Tallgrass Energy, LP for $85.0 million in net cash proceeds and recorded a gain on disposal of $33.4 million during the year ended March 31, 2019 within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations. These operations include five saltwater disposal wells located in McKenzie and Dunn Counties, North Dakota.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Water Solutions segment have not been classified as discontinued operations.

Sawtooth Joint Venture

On March 30, 2018, we completed the transaction to form a joint venture with Magnum Liquids, LLC, a portfolio company of Haddington Ventures LLC, along with Magnum Development, LLC and other Haddington-sponsored investment entities (collectively "Magnum") to focus on the storage of natural gas liquids and refined products by combining our Sawtooth salt dome storage facility with Magnum's refined products rights and adjacent leasehold. Magnum acquired an approximately 28.5% interest in Sawtooth from us, in exchange for consideration consisting of a cash payment of approximately $37.6 million (excluding working capital) and the contribution of certain refined products rights and adjacent leasehold, which we valued at $21.6 million and recorded within intangible assets in our consolidated balance sheet. The disposition of this interest was accounted for as an equity transaction, no gain or loss was recorded and the carrying value of the noncontrolling interest was adjusted to reflect the change in ownership interest of the subsidiary. We own approximately 71.5% of the joint venture; and within the next two years, Magnum has options to acquire our remaining interest for an additional $182.4 million.

Sale of Interest in Glass Mountain Pipeline, LLC ("Glass Mountain")

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain for net proceeds of $292.1 million and recorded a gain on disposal of $108.6 million during the three months ended December 31, 2017 within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Crude Oil Logistics segment have not been classified as discontinued operations.

Termination of a Storage Sublease Agreement

During the year ended March 31, 2017, we agreed to terminate a storage sublease agreement that was scheduled to commence in January 2017 and had a term of five years. For terminating this agreement, the counterparty agreed to pay us a specific amount in five equal payments which began in February 2017 and in January of the next four years and removed any future obligations of the Partnership. As a result, we discounted the future payments and recorded a gain of $16.2 million to other (expense) income, net in our consolidated statement of operations during the year ended March 31, 2017.

Termination of Development Agreement

On June 3, 2016, we entered into a purchase and sale agreement with the counterparty to the development agreement in our Water Solutions segment. Total cash consideration paid under the agreement was $49.6 million and in return we received the following:

- Termination of the development agreement (see Note 7);
- Additional interest in the water pipeline company we acquired in January 2016;
- Release of contingent consideration liabilities attributed to certain of our water treatment and disposal facilities;

- Certain parcels of land and permits to develop saltwater disposal wells and other parcels of land containing water wells and equipment; and
- A two-year non-compete agreement with the counterparty.

We accounted for the transaction as an acquisition of assets. We allocated $1.2 million of the total consideration to property, plant and equipment, $3.3 million to intangible assets, $2.8 million to noncontrolling interest, $25.5 million to the release of contingent consideration liabilities and $16.9 million to the termination of the development agreement. We recorded a $21.3 million gain on the release of $46.8 million of contingent consideration liabilities, which was recorded within (loss) gain on early extinguishment of liabilities, net in our consolidated statement of operations during the year ended March 31, 2017. For the termination of the development agreement, we recorded a loss of $22.7 million, which included the carrying value of the development agreement asset that was written off (see Note 7). This loss was recorded within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations during the year ended March 31, 2017.

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to ArcLight for approximately $112.4 million in cash and recorded a gain on disposal of $104.1 million during the year ended March 31, 2017. This gain is reported within loss (gain) on disposal or impairment of assets, net in our consolidated statement of operations.

Note 17—Assets, Liabilities and Redeemable Noncontrolling Interest Held for Sale and Discontinued Operations

As discussed in Note 1, as of June 30, 2018, we met the criteria for classifying the assets, liabilities and redeemable noncontrolling interest of our Retail Propane segment as held for sale and the operations as discontinued. On March 30, 2018, we sold a portion of our Retail Propane segment to DCC for net proceeds of $212.4 million in cash, and recorded a gain on disposal of $89.3 million during the year ended March 31, 2018. On July 10, 2018, we completed the sale of virtually all of our remaining Retail Propane segment to Superior for net proceeds of $889.8 million in cash, and recorded a gain on disposal of $408.9 million during the year ended March 31, 2019. On August 14, 2018, we sold our previously held interest in Victory Propane. See Note 1 for a further discussion.

The following table summarizes the major classes of assets, liabilities and redeemable noncontrolling interest classified as held for sale at March 31, 2018 (in thousands):

Assets Held for Sale		
Cash and cash equivalents	$	4,113
Accounts receivable-trade, net		45,924
Inventories		13,250
Prepaid expenses and other current assets		2,796
Property, plant and equipment, net		201,340
Goodwill		107,951
Intangible assets, net		141,328
Other assets		902
Total assets held for sale	$	517,604
Liabilities and Redeemable Noncontrolling Interest Held for Sale		
Accounts payable-trade	$	7,790
Accrued expenses and other payables		6,583
Advance payments received from customers		12,842
Current maturities of long-term debt		2,550
Long-term debt, net		2,888
Redeemable noncontrolling interest		9,927
Total liabilities and redeemable noncontrolling interest held for sale	$	42,580

The following table summarizes the results of operations from discontinued operations related to our former Retail Propane segment for the periods indicated:

	Year Ended March 31,		
	2019	2018	2017
	(in thousands)		
Revenues	$ 70,859	$ 521,511	$ 413,206
Cost of sales	36,758	269,367	191,589
Operating expenses	27,729	129,789	118,922
General and administrative expense	2,589	11,322	10,761
Depreciation and amortization	8,706	43,692	42,966
Gain on disposal or impairment of assets, net (1)	(407,608)	(88,209)	(287)
Operating income from discontinued operations	402,685	155,550	49,255
Equity in earnings (loss) of unconsolidated entities	1,183	425	(746)
Interest expense	(125)	(422)	(484)
Other income, net	364	1,330	1,052
Income from discontinued operations before taxes (2)	404,107	156,883	49,077
Income tax expense	(988)	(103)	(5)
Income from discontinued operations, net of tax	$ 403,119	$ 156,780	$ 49,072

(1) Amount for the year ended March 31, 2019 includes a gain of $408.9 million on the sale of virtually all of our remaining Retail Propane segment to Superior on July 10, 2018, partially offset by a loss of $1.3 million on the sale of a portion of our Retail Propane segment to DCC on March 30, 2018 related to a working capital adjustment.

(2) Amounts include income (loss) attributable to redeemable noncontrolling interests. Loss attributable to redeemable noncontrolling interest was $0.4 million for the year ended March 31, 2019 and income attributable to redeemable noncontrolling interest was $1.0 million for the year ended March 31, 2018.

Continuing Involvement

As of March 31, 2019, we have commitments to sell up to 7.4 million gallons of propane, valued at $5.7 million (based on the contract price) to Superior and DCC, the purchasers of our former Retail Propane segment, through March 2020. During the year ended March 31, 2019, we received a combined $84.2 million from Superior and DCC for propane sold to them during the period.

Note 18—Quarterly Financial Data (Unaudited)

The following tables summarize our unaudited quarterly financial data. The computation of net income (loss) per common unit is done separately by quarter and year. The total of net income (loss) per common unit of the individual quarters may not equal net income (loss) per common unit for the year, due primarily to the income allocation between the general partner and limited partners and variations in the weighted average units outstanding used in computing such amounts.

Our former Retail Propane segment's business (included within discontinued operations, see Note 17) is seasonal due to weather conditions in our service areas. Its results are affected by winter heating season requirements, which generally results in net income during the period from October through March of each year and either net losses or lower net income during the period from April through September of each year. Our Liquids segment is also subject to seasonal fluctuations, as demand for propane and butane is typically higher during the winter months. Our operating revenues from our other segments are less weather sensitive. Additionally, the acquisitions described in Note 4 impact the comparability of the quarterly information within the year, and year to year.

	Quarter Ended				Year Ended
	June 30, 2018	September 30, 2018	December 31, 2018	March 31, 2019	March 31, 2019
	(in thousands, except unit and per unit amounts)				
Total revenues	$ 5,844,434	$ 6,654,634	$ 6,376,820	$ 5,141,019	$ 24,016,907
Total cost of sales	$ 5,696,156	$ 6,509,527	$ 6,114,384	$ 4,964,850	$ 23,284,917
(Loss) income from continuing operations	$ (165,248)	$ (53,508)	$ 110,432	$ 44,600	$ (63,724)
Net (loss) income	$ (169,289)	$ 354,939	$ 110,528	$ 43,217	$ 339,395
Net (loss) income attributable to NGL Energy Partners LP	$ (168,546)	$ 355,505	$ 110,835	$ 62,253	$ 360,047
Basic (loss) income per common unit					
(Loss) income from continuing operations	$ (1.52)	$ (0.63)	$ 0.65	$ 0.21	$ (1.26)
Net (loss) income	$ (1.55)	$ 2.70	$ 0.65	$ 0.20	$ 2.01
Diluted (loss) income per common unit					
(Loss) income from continuing operations	$ (1.52)	$ (0.63)	$ 0.64	$ 0.20	$ (1.26)
Net (loss) income	$ (1.55)	$ 2.70	$ 0.64	$ 0.19	$ 2.01
Basic weighted average common units outstanding	121,544,421	122,380,197	123,892,680	124,262,014	123,017,064
Diluted weighted average common units outstanding	121,544,421	122,380,197	125,959,751	126,926,589	123,017,064

	Quarter Ended				Year Ended
	June 30, 2017	September 30, 2017	December 31, 2017	March 31, 2018	March 31, 2018
	(in thousands, except unit and per unit amounts)				
Total revenues	$ 3,730,705	$ 3,876,676	$ 4,353,783	$ 4,946,132	$ 16,907,296
Total cost of sales	$ 3,628,683	$ 3,757,450	$ 4,235,867	$ 4,790,641	$ 16,412,641
(Loss) income from continuing operations	$ (58,049)	$ (164,293)	$ 31,827	$ (35,870)	$ (226,385)
Net (loss) income	$ (63,707)	$ (173,579)	$ 56,769	$ 110,912	$ (69,605)
Net (loss) income attributable to NGL Energy Partners LP	$ (63,362)	$ (173,371)	$ 56,256	$ 109,602	$ (70,875)
Basic (loss) income per common unit					
(Loss) income from continuing operations	$ (0.56)	$ (1.49)	$ 0.13	$ (0.44)	$ (2.37)
Net (loss) income	$ (0.61)	$ (1.56)	$ 0.33	$ 0.76	$ (1.08)
Diluted (loss) income per common unit					
(Loss) income from continuing operations	$ (0.56)	$ (1.49)	$ 0.12	$ (0.28)	$ (2.37)
Net (loss) income	$ (0.61)	$ (1.56)	$ 0.32	$ 0.71	$ (1.08)
Basic weighted average common units outstanding	120,535,909	121,314,636	120,844,008	121,271,959	120,991,340
Diluted weighted average common units outstanding	120,535,909	121,314,636	124,161,966	146,868,349	120,991,340

The following summarizes significant items recognized during the years ended March 31, 2019 and 2018:

Year Ended March 31, 2019

- During the fourth quarter of fiscal year 2019, we recorded a goodwill impairment charge related to Sawtooth (see Note 6);
- On February 28, 2019, we sold our South Pecos water disposal business and recorded a gain (see Note 16);
- On November 30, 2018, we sold our Bakken saltwater disposal business and recorded a gain (see Note 16);
- On July 10, 2018, we sold virtually all of our remaining Retail Propane segment and recorded a gain (see Note 17);
- On May 3, 2018, we sold our previously held interest in E Energy Adams, LLC and recorded a gain (see Note 2); and
- During fiscal year 2019, we repurchased a portion of our 2019 Notes and 2023 Notes and redeemed the outstanding 2019 Notes and 2021 Notes and recorded a loss on the early extinguishment of these notes (see Note 8).

Year Ended March 31, 2018

- On March 30, 2018, we sold a portion of our Retail Propane segment to DCC and recorded a gain (see Note 17);
- On March 30, 2018, we closed the joint venture related to Sawtooth and sold a portion of our interest in Sawtooth (see Note 16);
- On December 22, 2017, we sold our previously held interest in Glass Mountain (see Note 16);
- During the second quarter of fiscal year 2018, we recorded a goodwill impairment charge related to Sawtooth (see Note 6);
- During fiscal year 2018, we repurchased a portion of our 2019 Notes, 2023 Notes and 2025 Notes and recorded a net gain on the early extinguishment of these notes (see Note 8); and
- During the first and third quarters of fiscal year 2018, we repurchased a portion of and then all of the remaining outstanding Senior Secured Notes and recorded a loss on the early extinguishment of these notes (see Note 8).

Note 19—Subsequent Events

Issuance of Class C Preferred Units

On April 2, 2019, we issued the Class C Preferred Units. See Note 10 for a further discussion.

Redemption of Class A Preferred Units

On April 5, 2019, we made a partial redemption of the Class A Preferred Units and on May 11, 2019, we redeemed the remaining outstanding Class A Preferred Units. See Note 10 for a further discussion. In connection with the redemption, Jared Parker resigned from the board of directors of our general partner.

Exercise of Warrants

On April 5, 2019, Oaktree exercised all of its remaining warrants to purchase common units. See Note 10 for a further discussion.

Issuance of 2026 Notes

On April 9, 2019, we issued the 2026 Notes. See Note 8 for a further discussion.

Acquisitions

On May 14, 2019, we entered into a definitive agreement with Mesquite Disposals Unlimited, LLC (“Mesquite”) to acquire all of its assets for approximately $892.5 million. Mesquite SWD Inc. will remain the operator of the Mesquite assets led by Mesquite’s current management team. The assets consist of a fully interconnected produced water pipeline transportation and disposal system in Eddy and Lea Counties, New Mexico, and Loving County, Texas. At closing, the Mesquite system is expected to have 35 saltwater disposal wells in total. The transaction is subject to certain regulatory and other customary closing conditions and is expected to close in July 2019.

On April 10, 2019, we acquired one saltwater disposal facility (including three saltwater disposal wells) for total consideration of approximately $53.0 million.

On April 3, 2019, we acquired land and two saltwater disposal wells for total consideration of approximately $13.0 million.

Note 20—Consolidating Guarantor and Non-Guarantor Financial Information

Certain of our wholly owned subsidiaries have, jointly and severally, fully and unconditionally guaranteed the Senior Unsecured Notes (see Note 8). Pursuant to Rule 3-10 of Regulation S-X, we have presented in columnar format the consolidating financial information for NGL Energy Partners LP (Parent), NGL Energy Finance Corp., the guarantor subsidiaries on a combined basis, and the non-guarantor subsidiaries on a combined basis in the tables below. NGL Energy Partners LP and NGL Energy Finance Corp. are co-issuers of the Senior Unsecured Notes. Since NGL Energy Partners LP received the proceeds from the issuance of the Senior Unsecured Notes, all activity has been reflected in the NGL Energy Partners LP (Parent) column in the tables below.

During the periods presented in the tables below, the status of certain subsidiaries changed, in that they either became guarantors of or ceased to be guarantors of the Senior Unsecured Notes. For purposes of the tables below, when the status of a subsidiary changes, all subsidiary activity is included in either the guarantor subsidiaries column or non-guarantor subsidiaries column based on the status of the subsidiary at the balance sheet date regardless of activity during the year.

There are no significant restrictions that prevent the parent or any of the guarantor subsidiaries from obtaining funds from their respective subsidiaries by dividend or loan. None of the assets of the guarantor subsidiaries (other than the investments in non-guarantor subsidiaries) are restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X under the Securities Act of 1933, as amended.

For purposes of the tables below, (i) the consolidating financial information is presented on a legal entity basis, (ii) investments in consolidated subsidiaries are accounted for as equity method investments, and (iii) contributions, distributions, and advances to (from) consolidated entities are reported on a net basis within net changes in advances with consolidated entities in the consolidating statement of cash flow tables below.

As discussed further in Note 1 and Note 17, the assets and liabilities related to our former Retail Propane segment have been classified as held for sale within our March 31, 2018 consolidated balance sheet and the results of operations and cash flows related to our former Retail Propane segment (including equity in earnings of Victory Propane) have been classified as discontinued operations for all periods presented and prior periods have been retrospectively adjusted in the consolidated statements of operations and consolidated statements of cash flows.

Consolidating Balance Sheet
(in Thousands)

	March 31, 2019					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 12,798	$ —	$ 3,728	$ 2,046	$ —	$ 18,572
Accounts receivable-trade, net of allowance for doubtful accounts	—	—	1,160,908	2,011	—	1,162,919
Accounts receivable-affiliates	—	—	12,867	—	—	12,867
Inventories	—	—	462,109	1,034	—	463,143
Prepaid expenses and other current assets	—	—	154,697	475	—	155,172
Total current assets	12,798	—	1,794,309	5,566	—	1,812,673
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation	—	—	1,635,637	208,856	—	1,844,493
GOODWILL	—	—	1,140,686	5,175	—	1,145,861
INTANGIBLE ASSETS, net of accumulated amortization	—	—	862,988	75,347	—	938,335
INVESTMENTS IN UNCONSOLIDATED ENTITIES	—	—	1,127	—	—	1,127
NET INTERCOMPANY RECEIVABLES (PAYABLES)	862,186	—	(808,610)	(53,576)	—	—
INVESTMENTS IN CONSOLIDATED SUBSIDIARIES	2,503,848	—	170,690	—	(2,674,538)	—
OTHER NONCURRENT ASSETS	—	—	160,004	—	—	160,004
Total assets	$ 3,378,832	$ —	$ 4,956,831	$ 241,368	$ (2,674,538)	$ 5,902,493
LIABILITIES AND EQUITY						
CURRENT LIABILITIES AND REDEEMABLE NONCONTROLLING INTEREST:						
Accounts payable-trade	$ —	$ —	$ 957,724	$ 6,941	$ —	$ 964,665
Accounts payable-affiliates	1	—	28,468	—	—	28,469
Accrued expenses and other payables	25,497	—	221,456	1,497	—	248,450
Advance payments received from customers	—	—	8,010	911	—	8,921
Current maturities of long-term debt	—	—	648	—	—	648
Total current liabilities and redeemable noncontrolling interest	25,498	—	1,216,306	9,349	—	1,251,153
LONG-TERM DEBT, net of debt issuance costs and current maturities	984,450	—	1,175,683	—	—	2,160,133
OTHER NONCURRENT LIABILITIES	—	—	60,994	2,581	—	63,575
CLASS A 10.75% CONVERTIBLE PREFERRED UNITS	149,814	—	—	—	—	149,814
EQUITY:						
Partners' equity	2,219,070	—	2,503,848	229,693	(2,733,286)	2,219,325
Accumulated other comprehensive loss	—	—	—	(255)	—	(255)
Noncontrolling interests	—	—	—	—	58,748	58,748
Total equity	2,219,070	—	2,503,848	229,438	(2,674,538)	2,277,818
Total liabilities and equity	$ 3,378,832	$ —	$ 4,956,831	$ 241,368	$ (2,674,538)	$ 5,902,493

Consolidating Balance Sheet
(in Thousands)

	March 31, 2018					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 16,915	$ —	$ 3,329	$ 1,850	$ —	$ 22,094
Accounts receivable-trade, net of allowance for doubtful accounts	—	—	1,021,616	5,148	—	1,026,764
Accounts receivable-affiliates	—	—	4,772	—	—	4,772
Inventories	—	—	550,978	325	—	551,303
Prepaid expenses and other current assets	—	—	128,311	431	—	128,742
Assets held for sale	—	—	490,800	26,804	—	517,604
Total current assets	16,915	—	2,199,806	34,558	—	2,251,279
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation	—	—	1,371,495	147,112	—	1,518,607
GOODWILL	—	—	1,127,347	77,260	—	1,204,607
INTANGIBLE ASSETS, net of accumulated amortization	—	—	829,449	83,705	—	913,154
INVESTMENTS IN UNCONSOLIDATED ENTITIES	—	—	17,236	—	—	17,236
NET INTERCOMPANY RECEIVABLES (PAYABLES)	2,110,940	—	(2,121,741)	10,801	—	—
INVESTMENTS IN CONSOLIDATED SUBSIDIARIES	1,703,327	—	244,109	—	(1,947,436)	—
LOAN RECEIVABLE-AFFILIATE	—	—	1,200	—	—	1,200
OTHER NONCURRENT ASSETS	—	—	245,039	—	—	245,039
Total assets	$ 3,831,182	$ —	$ 3,913,940	$ 353,436	$ (1,947,436)	$ 6,151,122
LIABILITIES AND EQUITY						
CURRENT LIABILITIES AND REDEEMABLE NONCONTROLLING INTEREST:						
Accounts payable-trade	$ —	$ —	$ 850,607	$ 2,232	$ —	$ 852,839
Accounts payable-affiliates	1	—	1,253	—	—	1,254
Accrued expenses and other payables	41,104	—	181,115	1,285	—	223,504
Advance payments received from customers	—	—	4,507	3,867	—	8,374
Current maturities of long-term debt	—	—	646	—	—	646
Liabilities and redeemable noncontrolling interest held for sale	—	—	30,066	12,514	—	42,580
Total current liabilities and redeemable noncontrolling interest	41,105	—	1,068,194	19,898	—	1,129,197
LONG-TERM DEBT, net of debt issuance costs and current maturities	1,704,909	—	974,831	—	—	2,679,740
OTHER NONCURRENT LIABILITIES	—	—	167,588	5,926	—	173,514
CLASS A 10.75% CONVERTIBLE PREFERRED UNITS	82,576	—	—	—	—	82,576
EQUITY:						
Partners' equity	2,002,592	—	1,704,896	327,858	(2,030,939)	2,004,407
Accumulated other comprehensive loss	—	—	(1,569)	(246)	—	(1,815)
Noncontrolling interests	—	—	—	—	83,503	83,503
Total equity	2,002,592	—	1,703,327	327,612	(1,947,436)	2,086,095
Total liabilities and equity	$ 3,831,182	$ —	$ 3,913,940	$ 353,436	$ (1,947,436)	$ 6,151,122

Consolidating Statement of Operations
(in Thousands)

	Year Ended March 31, 2019					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES	$ —	$ —	$ 23,993,347	$ 27,542	$ (3,982)	$ 24,016,907
COST OF SALES	—	—	23,287,875	1,024	(3,982)	23,284,917
OPERATING COSTS AND EXPENSES:						
Operating	—	—	227,216	13,468	—	240,684
General and administrative	—	—	106,722	812	—	107,534
Depreciation and amortization	—	—	202,400	10,460	—	212,860
(Gain) loss on disposal or impairment of assets, net	—	—	(31,924)	66,220	—	34,296
Revaluation of liabilities	—	—	(5,373)	—	—	(5,373)
Operating Income (Loss)	—	—	206,431	(64,442)	—	141,989
OTHER INCOME (EXPENSE):						
Equity in earnings of unconsolidated entities	—	—	2,533	—	—	2,533
Interest expense	(104,716)	—	(60,009)	(46)	45	(164,726)
Loss on early extinguishment of liabilities, net	(12,340)	—	—	—	—	(12,340)
Other expense, net	—	—	(29,715)	—	(231)	(29,946)
(Loss) Income From Continuing Operations Before Income Taxes	(117,056)	—	119,240	(64,488)	(186)	(62,490)
INCOME TAX EXPENSE	—	—	(1,234)	—	—	(1,234)
EQUITY IN NET INCOME (LOSS) FROM CONTINUING OPERATIONS OF CONSOLIDATED SUBSIDIARIES	477,103	—	(44,865)	—	(432,238)	—
Income (Loss) From Continuing Operations	360,047	—	73,141	(64,488)	(432,424)	(63,724)
Income (Loss) From Discontinued Operations, Net of Tax	—	—	403,962	(1,029)	186	403,119
Net Income (Loss)	360,047	—	477,103	(65,517)	(432,238)	339,395
LESS: NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS					20,206	20,206
LESS: NET LOSS ATTRIBUTABLE TO REDEEMABLE NONCONTROLLING INTERESTS					446	446
NET INCOME (LOSS) ATTRIBUTABLE TO NGL ENERGY PARTNER LP	$ 360,047	$ —	$ 477,103	$ (65,517)	$ (411,586)	$ 360,047

**Consolidating Statement of Operations
(in Thousands)**

	Year Ended March 31, 2018					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES	$ —	$ —	$ 16,888,834	$ 19,954	$ (1,492)	$ 16,907,296
COST OF SALES	—	—	16,412,642	1,491	(1,492)	16,412,641
OPERATING COSTS AND EXPENSES:						
Operating	—	—	194,048	7,020	—	201,068
General and administrative	—	—	97,552	577	—	98,129
Depreciation and amortization	—	—	198,119	10,901	—	209,020
(Gain) loss on disposal or impairment of assets, net	—	—	(133,979)	116,875	—	(17,104)
Revaluation of liabilities	—	—	20,124	592	—	20,716
Operating Income (Loss)	—	—	100,328	(117,502)	—	(17,174)
OTHER INCOME (EXPENSE):						
Equity in earnings of unconsolidated entities	—	—	7,539	—	—	7,539
Interest expense	(142,159)	—	(56,988)	(46)	45	(199,148)
Loss on early extinguishment of liabilities, net	(23,201)	—	—	—	—	(23,201)
Other income, net	—	—	7,753	19	(819)	6,953
(Loss) Income From Continuing Operations Before Income Taxes	(165,360)	—	58,632	(117,529)	(774)	(225,031)
INCOME TAX EXPENSE	—	—	(1,354)	—	—	(1,354)
EQUITY IN NET INCOME (LOSS) FROM CONTINUING OPERATIONS OF CONSOLIDATED SUBSIDIARIES	94,485	—	(116,224)	—	21,739	—
Loss From Continuing Operations	(70,875)	—	(58,946)	(117,529)	20,965	(226,385)
Income From Discontinued Operations, Net of Tax	—	—	153,431	2,575	774	156,780
Net (Loss) Income	(70,875)	—	94,485	(114,954)	21,739	(69,605)
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS					(240)	(240)
LESS: NET INCOME ATTRIBUTABLE TO REDEEMABLE NONCONTROLLING INTERESTS					(1,030)	(1,030)
NET (LOSS) INCOME ATTRIBUTABLE TO NGL ENERGY PARTNER LP	$ (70,875)	$ —	$ 94,485	$ (114,954)	$ 20,469	$ (70,875)

Consolidating Statement of Operations
(in Thousands)

	Year Ended March 31, 2017					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES	$ —	$ —	$ 12,688,354	$ 19,639	$ (790)	$ 12,707,203
COST OF SALES	—	—	12,228,661	533	(790)	12,228,404
OPERATING COSTS AND EXPENSES:						
Operating	—	—	182,476	6,527	—	189,003
General and administrative	—	—	105,402	403	—	105,805
Depreciation and amortization	—	—	172,798	7,441	—	180,239
Gain on disposal or impairment of assets, net	—	—	(208,890)	—	—	(208,890)
Revaluation of liabilities	—	—	6,305	412	—	6,717
Operating Income	—	—	201,602	4,323	—	205,925
OTHER INCOME (EXPENSE):						
Equity in earnings of unconsolidated entities	—	—	3,830	—	—	3,830
Revaluation of investments	—	—	(14,365)	—	—	(14,365)
Interest expense	(91,259)	—	(58,607)	(174)	46	(149,994)
Gain on early extinguishment of liabilities, net	8,507	—	16,220	—	—	24,727
Other income, net	—	—	27,205	—	(593)	26,612
(Loss) Income From Continuing Operations Before Income Taxes	(82,752)	—	175,885	4,149	(547)	96,735
INCOME TAX EXPENSE	—	—	(1,933)	—	—	(1,933)
EQUITY IN NET INCOME (LOSS) FROM CONTINUING OPERATIONS OF CONSOLIDATED SUBSIDIARIES	219,794	—	(1,336)	—	(218,458)	—
Income From Continuing Operations	137,042	—	172,616	4,149	(219,005)	94,802
Income From Discontinued Operations, Net of Tax	—	—	47,178	1,347	547	49,072
Net Income	137,042	—	219,794	5,496	(218,458)	143,874
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS					(6,832)	(6,832)
NET INCOME ATTRIBUTABLE TO NGL ENERGY PARTNER LP	$ 137,042	$ —	$ 219,794	$ 5,496	$ (225,290)	$ 137,042

Consolidating Statements of Comprehensive Income (Loss)
(in Thousands)

	Year Ended March 31, 2019					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income (loss)	$ 360,047	$ —	$ 477,103	$ (65,517)	$ (432,238)	$ 339,395
Other comprehensive (loss) income	—	—	(18)	9	—	(9)
Comprehensive income (loss)	$ 360,047	$ —	$ 477,085	$ (65,508)	$ (432,238)	$ 339,386

	Year Ended March 31, 2018					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net (loss) income	$ (70,875)	$ —	$ 94,485	$ (114,954)	$ 21,739	$ (69,605)
Other comprehensive income (loss)	—	—	58	(45)	—	13
Comprehensive (loss) income	$ (70,875)	$ —	$ 94,543	$ (114,999)	$ 21,739	$ (69,592)

	Year Ended March 31, 2017					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income	$ 137,042	$ —	$ 219,794	$ 5,496	$ (218,458)	$ 143,874
Other comprehensive loss	—	—	(1,626)	(45)	—	(1,671)
Comprehensive income	$ 137,042	$ —	$ 218,168	$ 5,451	$ (218,458)	$ 142,203

Consolidating Statement of Cash Flows
(in Thousands)

	Year Ended March 31, 2019					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
OPERATING ACTIVITIES:						
Net cash (used in) provided by operating activities-continuing operations	$ (116,033)	$ —	$ 451,284	$ (27,551)	$ (186)	$ 307,514
Net cash provided by operating activities-discontinued operations	—	—	26,515	3,221	—	29,736
Net cash (used in) provided by operating activities	(116,033)	—	477,799	(24,330)	(186)	337,250
INVESTING ACTIVITIES:						
Capital expenditures	—	—	(414,549)	(41,064)	—	(455,613)
Acquisitions, net of cash acquired	—	—	(313,009)	(3,927)	—	(316,936)
Net settlements of commodity derivatives	—	—	18,405	—	—	18,405
Proceeds from sales of assets	—	—	16,177	—	—	16,177
Proceeds from divestitures of businesses and investments, net	—	—	335,809	—	—	335,809
Investments in unconsolidated entities	—	—	(389)	—	—	(389)
Distributions of capital from unconsolidated entities	—	—	1,440	—	—	1,440
Repayments on loan for natural gas liquids facility	—	—	10,336	—	—	10,336
Loan to affiliate	—	—	(1,515)	—	—	(1,515)
Net cash used in investing activities-continuing operations	—	—	(347,295)	(44,991)	—	(392,286)
Net cash provided by investing activities-discontinued operations	—	—	838,777	6,982	—	845,759
Net cash provided by (used in) investing activities	—	—	491,482	(38,009)	—	453,473
FINANCING ACTIVITIES:						
Proceeds from borrowings under revolving credit facilities	—	—	4,098,500	—	—	4,098,500
Payments on revolving credit facilities	—	—	(3,897,000)	—	—	(3,897,000)
Repayment and repurchase of senior secured and senior unsecured notes	(737,058)	—	—	—	—	(737,058)
Payments on other long-term debt	—	—	(653)	—	—	(653)
Debt issuance costs	(30)	—	(1,353)	—	—	(1,383)
Contributions from noncontrolling interest owners, net	—	—	—	169	—	169
Distributions to general and common unit partners and preferred unitholders	(236,633)	—	—	—	—	(236,633)
Repurchase of warrants	(14,988)	—	—	—	—	(14,988)
Common unit repurchases and cancellations	(297)	—	—	—	—	(297)
Payments for settlement and early extinguishment of liabilities	—	—	(4,577)	—	—	(4,577)
Net changes in advances with consolidated entities	1,100,922	—	(1,163,504)	62,396	186	—
Net cash provided by (used in) financing activities-continuing operations	111,916	—	(968,587)	62,565	186	(793,920)
Net cash used in financing activities-discontinued operations	—	—	(295)	(30)	—	(325)
Net cash provided by (used in) financing activities	111,916	—	(968,882)	62,535	186	(794,245)
Net (decrease) increase in cash and cash equivalents	(4,117)	—	399	196	—	(3,522)
Cash and cash equivalents, beginning of period	16,915	—	3,329	1,850	—	22,094
Cash and cash equivalents, end of period	$ 12,798	$ —	$ 3,728	$ 2,046	$ —	$ 18,572

Consolidating Statement of Cash Flows
(in Thousands)

	Year Ended March 31, 2018					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
OPERATING ACTIVITIES:						
Net cash (used in) provided by operating activities-continuing operations	$ (141,967)	$ —	$ 186,959	$ 9,411	$ (774)	$ 53,629
Net cash provided by operating activities-discontinued operations	—	—	80,857	3,481	—	84,338
Net cash (used in) provided by operating activities	(141,967)	—	267,816	12,892	(774)	137,967
INVESTING ACTIVITIES:						
Capital expenditures	—	—	(130,760)	(3,001)	—	(133,761)
Acquisitions, net of cash acquired	—	—	3,100	(22,997)	—	(19,897)
Net settlements of commodity derivatives	—	—	(100,405)	—	—	(100,405)
Proceeds from sales of assets	—	—	33,844	—	—	33,844
Proceeds from divestitures of businesses and investments, net	—	—	292,112	37,668	—	329,780
Transaction with Victory Propane (Note 13)	—	—	(6,424)	—	—	(6,424)
Investments in unconsolidated entities	—	—	(21,465)	—	—	(21,465)
Distributions of capital from unconsolidated entities	—	—	11,969	—	—	11,969
Repayments on loan for natural gas liquids facility	—	—	10,052	—	—	10,052
Loan to affiliate	—	—	(2,510)	—	—	(2,510)
Repayments on loan to affiliate	—	—	4,160	—	—	4,160
Net cash provided by investing activities-continuing operations	—	—	93,673	11,670	—	105,343
Net cash provided by (used in) investing activities-discontinued operations	—	—	165,958	(719)	—	165,239
Net cash provided by investing activities	—	—	259,631	10,951	—	270,582
FINANCING ACTIVITIES:						
Proceeds from borrowings under revolving credit facilities	—	—	2,434,500	—	—	2,434,500
Payments on revolving credit facilities	—	—	(2,279,500)	—	—	(2,279,500)
Repayment and repurchase of senior secured and senior unsecured notes	(486,699)	—	—	—	—	(486,699)
Payments on other long-term debt	—	—	(877)	—	—	(877)
Debt issuance costs	(692)	—	(2,008)	—	—	(2,700)
Contributions from noncontrolling interest owners, net	—	—	—	23	—	23
Distributions to general and common unit partners and preferred unitholders	(225,067)	—	—	—	—	(225,067)
Distributions to noncontrolling interest owners	—	—	—	(3,082)	—	(3,082)
Proceeds from sale of preferred units, net of offering costs	202,731	—	—	—	—	202,731
Repurchase of warrants	(10,549)	—	—	—	—	(10,549)
Common unit repurchases and cancellations	(15,817)	—	—	—	—	(15,817)
Payments for settlement and early extinguishment of liabilities	—	—	(3,408)	—	—	(3,408)
Net changes in advances with consolidated entities	688,718	—	(669,452)	(20,040)	774	—
Net cash provided by (used in) financing activities-continuing operations	152,625	—	(520,745)	(23,099)	774	(390,445)
Net cash used in financing activities-discontinued operations	—	—	(3,446)	(390)	—	(3,836)
Net cash provided by (used in) financing activities	152,625	—	(524,191)	(23,489)	774	(394,281)
Net increase in cash and cash equivalents	10,658	—	3,256	354	—	14,268
Cash and cash equivalents, beginning of period	6,257	—	73	1,496	—	7,826
Cash and cash equivalents, end of period	$ 16,915	$ —	$ 3,329	$ 1,850	$ —	$ 22,094

Consolidating Statement of Cash Flows
(in Thousands)

	Year Ended March 31, 2017					
	NGL Energy Partners LP (Parent)	NGL Energy Finance Corp.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
OPERATING ACTIVITIES:						
Net cash (used in) provided by operating activities-continuing operations	$ (749,250)	$ —	$ 635,322	$ 16,675	$ (547)	$ (97,800)
Net cash provided by operating activities-discontinued operations	—	—	67,733	5,029	—	72,762
Net cash (used in) provided by operating activities	(749,250)	—	703,055	21,704	(547)	(25,038)
INVESTING ACTIVITIES:						
Capital expenditures	—	—	(338,569)	(6,367)	—	(344,936)
Acquisitions, net of cash acquired	—	—	(41,928)	—	—	(41,928)
Net settlements of commodity derivatives	—	—	(37,086)	—	—	(37,086)
Proceeds from sales of assets	—	—	28,232	—	—	28,232
Proceeds from divestitures of businesses and investments, net	—	—	112,370	22,000	—	134,370
Investments in unconsolidated entities	—	—	(2,105)	—	—	(2,105)
Distributions of capital from unconsolidated entities	—	—	9,692	—	—	9,692
Repayments on loan for natural gas liquids facility	—	—	8,916	—	—	8,916
Loan to affiliate	—	—	(3,200)	—	—	(3,200)
Repayments on loan to affiliate	—	—	655	—	—	655
Payment to terminate development agreement	—	—	(16,875)	—	—	(16,875)
Net cash (used in) provided by investing activities-continuing operations	—	—	(279,898)	15,633	—	(264,265)
Net cash used in investing activities-discontinued operations	—	—	(86,463)	(12,398)	—	(98,861)
Net cash (used in) provided by investing activities	—	—	(366,361)	3,235	—	(363,126)
FINANCING ACTIVITIES:						
Proceeds from borrowings under revolving credit facilities	—	—	1,700,000	—	—	1,700,000
Payments on revolving credit facilities	—	—	(2,733,500)	—	—	(2,733,500)
Issuance of senior unsecured notes	1,200,000	—	—	—	—	1,200,000
Repayment and repurchase of senior secured and senior unsecured notes	(21,193)	—	—	—	—	(21,193)
Payments on other long-term debt	—	—	(46,153)	—	—	(46,153)
Debt issuance costs	(21,868)	—	(11,690)	—	—	(33,558)
Contributions from general partner	49	—	—	—	—	49
Contributions from noncontrolling interest owners, net	—	—	—	672	—	672
Distributions to general and common unit partners and preferred unitholders	(181,581)	—	—	—	—	(181,581)
Distributions to noncontrolling interest owners	—	—	—	(3,292)	—	(3,292)
Proceeds from sale of preferred units, net of offering costs	234,975	—	—	—	—	234,975
Proceeds from sale of common units, net of offering costs	287,136	—	—	—	—	287,136
Payments for settlement and early extinguishment of liabilities	—	—	(28,468)	—	—	(28,468)
Net changes in advances with consolidated entities	(767,760)	—	788,334	(21,121)	547	—
Net cash provided by (used in) financing activities-continuing operations	729,758	—	(331,477)	(23,741)	547	375,087
Net cash used in financing activities-discontinued operations	—	—	(3,443)	(190)	—	(3,633)
Net cash provided by (used in) financing activities	729,758	—	(334,920)	(23,931)	547	371,454
Net (decrease) increase in cash and cash equivalents	(19,492)	—	1,774	1,008	—	(16,710)
Cash and cash equivalents, beginning of period	25,749	—	(1,701)	488	—	24,536

Cash and cash equivalents, end of period	$ 6,257	$ —	$ 73	$ 1,496	$ —	$ 7,826