Enable Midstream Partners, LP
Form 10-Q
August 02, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____
Commission File No. 1-36413

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

Delaware	72-1252419
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Leadership Square
211 North Robinson Avenue
Suite 150
Oklahoma City, Oklahoma 73102
(Address of principal executive offices)
(Zip Code)

(405) 525-7788
Registrant’s telephone number, including area code

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. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	þ	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

As of July 13, 2018, there were 433,068,427 common units outstanding.

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AVAILABLE INFORMATION

Our website is www.enablemidstream.com. On the investor relations tab of our website, http://investors.enablemidstream.com, we make available free of charge a variety of information to investors. Our goal is to maintain the investor relations tab of our website as a portal through which investors can easily find or navigate to pertinent information about us, including but not limited to:

- our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after we electronically file that material with or furnish it to the SEC;
- press releases on quarterly distributions, quarterly earnings, and other developments;
- governance information, including our governance guidelines, committee charters, and code of ethics and business conduct;
- information on events and presentations, including an archive of available calls, webcasts, and presentations;
- news and other announcements that we may post from time to time that investors may find useful or interesting; and
- opportunities to sign up for email alerts and RSS feeds to have information pushed in real time.

Information contained on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

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GLOSSARY OF TERMS

2015 Term Loan Agreement.	$450 million unsecured term loan agreement.
2019 Notes.	$500 million aggregate principal amount of the Partnership's 2.400% senior notes due 2019.
2024 Notes.	$600 million aggregate principal amount of the Partnership's 3.900% senior notes due 2024.
2027 Notes.	$700 million aggregate principal amount of the Partnership's 4.400% senior notes due 2027.
2028 Notes.	$800 million aggregate principal amount of the Partnership's 4.950% senior notes due 2028.
2044 Notes.	$550 million aggregate principal amount of the Partnership's 5.000% senior notes due 2044.
Adjusted EBITDA.	A non-GAAP measure calculated as net income attributable to limited partners plus depreciation and amortization expense, interest expense, net of interest income, income tax expense, distributions received from equity method affiliate in excess of equity earnings, non-cash equity-based compensation, changes in fair value of derivatives, certain other non-cash gains and losses (including gains and losses on sales of assets and write-downs of materials and supplies) and impairments, less the noncontrolling interest allocable to Adjusted EBITDA.
Adjusted interest expense.	A non-GAAP measure calculated as interest expense plus amortization of premium on long-term debt and capitalized interest on expansion capital, less amortization of debt costs and discount on long-term debt.
Annual Report.	Annual Report on Form 10-K for the year ended December 31, 2017.
ArcLight.	ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P., Bronco Midstream Infrastructure LLC and Enogex Holdings LLC, and their respective general partners and subsidiaries.
ASC.	Accounting Standards Codification.
ASU.	Accounting Standards Update.
ATM Program.	The offer and sale, from time to time, of common units representing limited partner interest having an aggregate offering price of up to $200 million in quantities, by sales methods and at prices determined by market conditions and other factors at the time of such sales, pursuant to that certain ATM Equity Offering Sales Agreement, entered into on May 12, 2017.
Barrel.	42 U.S. gallons of petroleum products.
Bbl.	Barrel.
Bbl/d.	Barrels per day.
Bcf/d.	Billion cubic feet per day.
Btu.	British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
DCF.	Distributable Cash Flow, a non-GAAP measure calculated as Adjusted EBITDA, as further adjusted for Series A Preferred Unit distributions, distributions for phantom and performance units, Adjusted interest expense, maintenance capital expenditures and current income taxes.
Distribution coverage ratio.	A non-GAAP measure calculated as DCF divided by distributions related to common and subordinated unitholders.
DRIP.	Distribution Reinvestment Plan entered into on June 23, 2016, which offers owners of our common units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common units.

EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates an approximately 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex Basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates an approximately 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
EOIT Senior Notes.	$250 million 6.25% senior notes due 2020.

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Exchange Act.	Securities Exchange Act of 1934, as amended.
FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Generally accepted accounting principles in the United States.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.
Gross margin.	A non-GAAP measure calculated as Total revenues minus Cost of natural gas and natural gas liquids, excluding depreciation and amortization.
LDC.	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area.
LIBOR.	London Interbank Offered Rate.
March 31 Quarterly Report	Quarterly Report on Form 10-Q for the period ended March 31, 2018.
MBbl.	Thousand barrels.
MBbl/d.	Thousand barrels per day.
MMcf.	Million cubic feet of natural gas.
MMcf/d.	Million cubic feet per day.
MRT.	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 1,600-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries.
Partnership.	Enable Midstream Partners, LP, and its subsidiaries.
Partnership Agreement.	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of November 14, 2017.
Revolving Credit Facility.	$1.75 billion senior unsecured revolving credit facility.
SEC.	Securities and Exchange Commission.
Series A Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% interest, that operates an approximately 290-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
WTI.	West Texas Intermediate.

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FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as “could,” “will,” “should,” “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “p “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-loo statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in our Annual Report and in our March 31 Quarterly Report. Those risk factors and other factors noted throughout this report and in our Annual Report and in our March 31 Quarterly Report could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by our customers and competitors;
- the supply and demand for natural gas, NGLs, crude oil and midstream services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- strategic decisions by CenterPoint Energy and OGE Energy regarding their ownership of us and Enable GP;
- operating hazards and other risks incidental to transporting, storing, gathering and processing natural gas, NGLs, crude oil and midstream products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- the timing and extent of changes in labor and material prices;
- labor relations;
- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- changes in insurance markets impacting costs and the level and types of coverage available;
- the timing and extent of changes in commodity prices;
- the suspension, reduction or termination of our customers’ obligations under our commercial agreements;
- disruptions due to equipment interruption or failure at our facilities, or third-party facilities on which our business is dependent;
- the effects of future litigation; and
- other factors set forth in this report and our other filings with the SEC, including our Annual Report and in our March 31 Quarterly Report.

Forward-looking statements speak only as of the date on which they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions, except per unit data)			
Revenues (including revenues from affiliates (Note 12)):				
Product sales	$501	$354	$944	$740
Service revenues	304	272	609	552
Total Revenues	805	626	1,553	1,292
Cost and Expenses (including expenses from affiliates (Note 12)):				
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	444	279	819	587
Operation and maintenance	97	97	191	186
General and administrative	26	23	53	48
Depreciation and amortization	96	89	192	177
Taxes other than income tax	16	16	33	32
Total Cost and Expenses	679	504	1,288	1,030
Operating Income	126	122	265	262
Other Income (Expense):				
Interest expense	(36)	(31)	(69)	(58)
Equity in earnings of equity method affiliate	7	7	13	14
Other, net	(2)	(1)	—	—
Total Other Expense	(31)	(25)	(56)	(44)
Income Before Income Tax	95	97	209	218
Income tax expense	—	1	—	2
Net Income	$95	$96	$209	$216
Less: Net income attributable to noncontrolling interest	—	1	—	1
Net Income Attributable to Limited Partners	$95	$95	$209	$215
Less: Series A Preferred Unit distributions (Note 6)	9	9	18	18
Net Income Attributable to Common and Subordinated Units (Note 5)	$86	$86	$191	$197
Basic earnings per unit (Note 5)				
Common units	$0.20	$0.20	$0.44	$0.45
Subordinated units	$—	$0.20	$—	$0.46
Diluted earnings per unit (Note 5)				
Common units	$0.20	$0.20	$0.44	$0.45
Subordinated units	$—	$0.20	$—	$0.46

See Notes to the Unaudited Condensed Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2018	December 31, 2017
	(In millions)	
Current Assets:		
Cash and cash equivalents	$7	$ 5
Restricted cash (Note 1)	14	14
Accounts receivable, net of allowance for doubtful accounts (Note 1)	287	277
Accounts receivable—affiliated companies	21	18
Inventory	41	40
Gas imbalances	29	37
Other current assets	33	25
Total current assets	432	416
Property, Plant and Equipment:		
Property, plant and equipment	12,443	12,079
Less accumulated depreciation and amortization	1,880	1,724
Property, plant and equipment, net	10,563	10,355
Other Assets:		
Intangible assets, net	429	451
Goodwill	12	12
Investment in equity method affiliate	315	324
Other	41	35
Total other assets	797	822
Total Assets	$11,792	$ 11,593
Current Liabilities:		
Accounts payable	$244	$ 263
Accounts payable—affiliated companies	3	3
Current portion of long-term debt	499	450
Short-term debt	327	405
Taxes accrued	39	32
Gas imbalances	16	12
Other	130	114
Total current liabilities	1,258	1,279
Other Liabilities:		
Accumulated deferred income taxes, net	6	6
Regulatory liabilities	22	21
Other	54	38
Total other liabilities	82	65
Long-Term Debt	2,881	2,595
Commitments and Contingencies (Note 13)		
Partners’ Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at June 30, 2018 and December 31, 2017)	362	362
Common units (433,064,636 issued and outstanding at June 30, 2018 and 432,584,080 issued and outstanding at December 31, 2017, respectively)	7,198	7,280
Noncontrolling interest	11	12

Total Partners’ Equity	7,571	7,654
Total Liabilities and Partners’ Equity	$11,792	$ 11,593

See Notes to the Unaudited Condensed Consolidated Financial Statements
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ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2018	2017
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$209	$216
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	192	177
Deferred income taxes	—	2
Loss on sale/retirement of assets	—	5
Equity in earnings of equity method affiliate	(13)	(14)
Return on investment in equity method affiliate	13	14
Equity-based compensation	8	8
Amortization of debt costs and discount (premium)	(1)	(1)
Changes in other assets and liabilities:		
Accounts receivable, net	(9)	29
Accounts receivable—affiliated companies	(3)	(1)
Inventory	(2)	(1)
Gas imbalance assets	8	18
Other current assets	(15)	(2)
Other assets	(5)	3
Accounts payable	(19)	(46)
Gas imbalance liabilities	4	(26)
Other current liabilities	22	3
Other liabilities	16	(2)
Net cash provided by operating activities	405	382
Cash Flows from Investing Activities:		
Capital expenditures	(375)	(148)
Proceeds from sale of assets	8	1
Proceeds from insurance	1	—
Return of investment in equity method affiliate	8	5
Net cash used in investing activities	(358)	(142)
Cash Flows from Financing Activities:		
Decrease in short-term debt	(78)	—
Repayment of long-term debt	(450)	—
Proceeds from long-term debt, net of issuance costs	787	691
Proceeds from Revolving Credit Facility	—	394
Repayment of Revolving Credit Facility	—	(1,030)
Distributions	(295)	(296)
Cash paid for employee equity-based compensation	(9)	(1)
Net cash used in financing activities	(45)	(242)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	2	(2)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	19	23
Cash, Cash Equivalents and Restricted Cash at End of Period	$21	$21

See Notes to the Unaudited Condensed Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(Unaudited)

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
	(In millions)							
Balance as of December 31, 2016	15	$362	224	$3,737	208	$3,683	$ 12	$7,794
Net income	—	18	—	102	—	95	1	216
Distributions	—	(18)	—	(144)	—	(132)	(1)	(295)
Equity-based compensation, net of units for employee taxes	—	—	—	7	—	—	—	7
Balance as of June 30, 2017	15	$362	224	$3,702	208	$3,646	$ 12	$7,722
Balance as of December 31, 2017	15	$362	433	$7,280	—	$—	$ 12	$7,654
Net income	—	18	—	191	—	—		209
Distributions	—	(18)	—	(276)	—	—	(1)	(295)
Equity-based compensation, net of units for employee taxes	—			3	—	—	—	3
Balance as of June 30, 2018	15	$362	433	$7,198	—	$—	$ 11	$7,571

See Notes to the Unaudited Condensed Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP is a Delaware limited partnership formed on May 1, 2013 by CenterPoint Energy, OGE Energy and ArcLight. The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers. The Partnership's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. The Partnership's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma, and our investment in SESH, an interstate pipeline extending from Louisiana to Alabama.

CenterPoint Energy and OGE Energy each have 50% of the management interests in Enable GP. Enable GP is the general partner of the Partnership and has no other operating activities. Enable GP is governed by a board made up of two representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and three independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

As of June 30, 2018, CenterPoint Energy held approximately 54.0% or 233,856,623 of the Partnership's common units, and OGE Energy held approximately 25.6% or 110,982,805 of the Partnership's common units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 6 for further information related to the Series A Preferred Units. The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's general partner on an annual or continuing basis and may not remove Enable GP, its current general partner, without at least a 75% vote by all unitholders, including all units held by the Partnership's limited partners, and Enable GP and its affiliates, voting together as a single class.

As of June 30, 2018, the Partnership owned a 50% interest in SESH. See Note 7 for further discussion of SESH.

Basis of Presentation

The accompanying condensed consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP. Pursuant to such rules and regulations, certain disclosures normally included in financial statements prepared in accordance with GAAP have been omitted. The accompanying condensed consolidated financial statements and related notes should be read in conjunction with the consolidated financial statements and related notes included in our Annual Report.

The condensed consolidated financial statements and the related notes reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. Amounts reported in the Partnership’s Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c) timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests.

For a description of the Partnership’s reportable segments, see Note 15.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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Restricted Cash

Restricted cash primarily consists of cash collateral which is provided as credit assurance by third parties. The Condensed Consolidated Balance Sheets have $14 million of restricted cash at each of June 30, 2018 and December 31, 2017.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, management evaluates our customers' financial strength based on aging of accounts receivable, payment history, and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $2 million allowance for doubtful accounts was required at June 30, 2018 and a $3 million allowance at December 31, 2017.

Inventory

Natural gas inventory is held, through the transportation and storage segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the gathering and processing segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or net realizable value. The Partnership's Inventory balance is net of $1 million and zero lower of cost or net realizable value adjustments as of June 30, 2018 and December 31, 2017, respectively.

Income Taxes

The Partnership's earnings are not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future taxes attributable to the difference between financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of tax net operating loss carryforwards. In the event future utilization is determined to be unlikely, a valuation allowance is provided to reduce the tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the period in which the temporary differences and carryforwards are expected to be recovered or settled. The effect of a change in tax rates is recognized in the period which includes the enactment date. The Partnership recognizes interest and penalties as a component of income tax expense.

(2) New Accounting Pronouncements

Accounting Standards to be Adopted in Future Periods

Leases

In February 2016, the FASB issued ASU 2016-02, “Leases (ASC 842).” This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

In January 2018, the FASB issued ASU 2018-01, “Land Easement Practical Expedient for Transition to Topic 842.” This standard permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expire before the Partnership's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. The Partnership intends to elect this transition provision.

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In July 2018, the FASB issued ASU No. 2018-10, “Codification Improvements to Topic 842, Leases,” which finalizes Proposed Accounting Standards Update (ASU) No. 2017-310, Technical Corrections and Improvements to Recently Issued Standards-Accounting Standards Update No. 2016-02, Leases (Topic 842), to address implementation issues that could arise as organizations comply with ASU No. 2016-02, Leases (Topic 842). We are currently evaluating this ASU and its potential impact on our implementation.

The Partnership continues to review contracts and easements relative to the provisions of the ASU 2016-02 lease standard, the ASU 2018-01 easement standard and the ASU 2018-10 codification improvements standard, as well as to monitor relevant emerging industry guidance regarding the implementation of the standards. As part of this analysis, we are evaluating the potential information technology and internal control changes that will be required for adoption based on the findings from our contract and easement review process. While we have not estimated the quantitative effect that ASC 842 will have on our consolidated financial statements, the adoption of ASC 842 will increase our asset and liability balances on the consolidated balance sheets due to the required recognition of right-of-use assets and corresponding lease liabilities for all lease obligations that are currently classified as operating leases. The Partnership expects to adopt these standards in the first quarter of 2019 and continues to evaluate the other impact of the standards on our Condensed Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions, and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

Compensation—Stock Compensation

In June 2018, the FASB issued ASU No. 2018-07, “Compensation-Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Payment Accounting.” This standard requires entities to include share-based payment transactions for acquiring goods and services from non-employees. The standard is effective for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

(3) Revenues

The Partnership adopted ASU No. 2014-09, “Revenue from Contracts with Customers” (ASC 606) on January 1, 2018 using the modified retrospective method. Upon adoption, the Partnership did not recognize a material cumulative adjustment to Partners’ Equity and there were no material changes in the timing of revenue recognition or our accounting policies. The Partnership has applied the standard to only contracts that were not expired as of January 1, 2018.

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The following table disaggregates total revenues by major source from contracts with customers and the gain (loss) on derivative activity for the three and six months ended June 30, 2018, and 2017.

	Three Months Ended June 30, 2018			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$106	$ 143	$ (107)	$142
Natural gas liquids	336	6	(6)	336
Condensate	37	—	—	37
Total revenues from natural gas, natural gas liquids, and condensate	479	149	(113)	515
Gain (loss) on derivative activity	(14)	—	—	(14)
Total Product sales	$465	$ 149	$ (113)	$501
Service revenues:				
Demand revenues	$52	$ 113	$ —	$165
Volume-dependent revenues	124	15	—	139
Total Service revenues	$176	$ 128	$ —	$304
Total Revenues	$641	$ 277	$ (113)	$805

	Six Months Ended June 30, 2018			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$212	$ 274	$ (216)	$270
Natural gas liquids	615	13	(13)	615
Condensate	73	—	—	73
Total revenues from natural gas, natural gas liquids, and condensate	900	287	(229)	958
Gain (loss) on derivative activity	(17)	2	1	(14)
Total Product sales	$883	$ 289	$ (228)	$944
Service revenues:				
Demand revenues	$102	$ 233	$ —	$335
Volume-dependent revenues	247	34	(7)	274
Total Service revenues	$349	$ 267	$ (7)	$609
Total Revenues	$1,232	$ 556	$ (235)	$1,553

Product Sales

Natural Gas, NGLs or Condensate

We deliver natural gas, NGLs and condensate to purchasers at contractually agreed-upon delivery points at which the purchaser takes custody, title, and risk of loss of the commodity. We recognize revenue when control transfers to the purchaser at the delivery point based on the contractually agreed upon fixed or index based price received.

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Gain (Loss) on Derivative Activity

Included in Product sales are gains and losses on natural gas, natural gas liquids, and crude oil (for condensate) derivatives that are accounted for under guidance in ASC 815. See Note 9 for further discussion of our derivative and hedging activity.

Service Revenues

Demand revenues

Our demand revenue arrangements are generally structured in one of the following ways:

- Under a firm fee arrangement, a customer agrees to pay a fixed fee for a contractually agreed upon pipeline or storage capacity. Once the services have been completed, or the customer no longer has access to the contracted capacity, revenue is recognized.
- Under a minimum volume commitment fee arrangement, a customer agrees to pay a contractually agreed upon gathering, compressing and treating fees for a minimum volume of natural gas or crude oil irrespective of whether or not the minimum volume of natural gas or crude oil is delivered. If the actual volumes exceed the minimum volume of natural gas or crude oil, the customer pays the contractually agreed upon gathering, compressing and treating fees for the excess volumes in addition to the fees paid for the minimum volume of natural gas or crude oil. Certain of our contracts provide our customers the option to elect to pay a higher gathering fee over the remaining term of the contract in lieu of making a contractually agreed upon shortfall payment. Once the services have been completed, or the customer no longer has the ability to utilize the services, revenue is recognized.

Volume-dependent revenues

Our volume-dependent revenues primarily consist of gathering, compressing, treating, processing, transportation or storage services fees on contracts that exceed their contractually committed volume or do not have firm fee arrangements or minimum volume commitments. These fees are dependent on throughput by third party customers, and revenue is recognized over time as the service is performed. Our other fee revenue arrangements have pricing terms that are generally structured in one of the following ways: (1) Contractually agreed upon monetary fee for service or (2) contractually agreed upon consideration received in the form of natural gas or natural gas liquids, which are valued at the current month index based price, which approximates fair value.

Accounts Receivable

Payments for all types of revenues are typically received within 30 days of invoice. Invoices for all revenue types are sent on at least a monthly basis, except for the shortfall provisions under certain minimum volume commitment contracts, which are typically invoiced annually. Accounts receivable includes accrued revenues associated with certain minimum volume commitments that will be invoiced at the conclusion of the measurement period specified under the respective contracts.

	June 30, 2018	December 31, 2017
	(In millions)	
Accounts Receivable:		
Customers	$289	$ 265
Contract assets [(1)]	13	27
Non-customers	6	3
Total Accounts Receivable [(2)]	$308	$ 295

(1)Contract assets include accrued minimum volume commitments and firm service transportation contracts with tiered rates.
(2)Total Accounts Receivable includes Accounts receivables, net of allowance for doubtful accounts and Accounts receivable—affiliated companies.

Contract Liabilities

Our contract liabilities primarily consist of the following prepayments received from customers:

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- Under certain firm fee arrangements, customers pay their demand fee prior to the month of contracted capacity. These fees are applied to the subsequent month's activity and are included in other liabilities on the Condensed Consolidated Balance Sheets.
- Under certain demand and volume dependent arrangements, customers make contributions of aid in construction payments. For payments that are related to contracts under ASC 606, the payment is deferred and amortized over the life of the associated contract and the unamortized balance is included in other current or long-term liabilities on the Condensed Consolidated Balance Sheets.

The table below summarizes the change in the contract liabilities for the six months ended June 30, 2018:

	June 30, 2018	December 31, 2017	Amounts recognized in revenues
	(In millions)		
Deferred revenues	$49	$ 34	$ 17

The table below summarizes the timing of recognition of these contract liabilities as of June 30, 2018:

	2018	2019	2020	2021	2022 and After
	(In millions)				
Deferred revenues	$21	$ 5	$ 5	$ 5	$ 13

Remaining Performance Obligations

Our remaining performance obligations consist primarily of firm fee and minimum volume commitment fee arrangements. Upon completion of the performance obligations associated with these arrangements, customers are invoiced and revenue is recognized as Service revenues in the Condensed Consolidated Statements of Income.

The table below summarizes the timing of recognition of the remaining performance obligations as of June 30, 2018:

	2018	2019	2020	2021	2022 and After
Transportation and Storage	$235	$373	$272	$149	$746
Gathering and Processing	128	261	160	136	602
Total remaining performance obligations	$363	$634	$432	$285	$1,348

Impact of Adoption

Upon adoption of ASC 606, the recognition of revenues for certain contractual arrangements was impacted as follows:

- Natural gas and natural gas liquids purchase arrangements - For certain arrangements within our gathering and processing segment, the Partnership purchases and controls the entire hydrocarbon stream at the point of receipt. As of January 1, 2018, these arrangements are considered supplier contracts rather than contracts with customers. Therefore, beginning January 1, 2018, the gathering and processing fees for these arrangements that were previously recognized as Service revenues under ASC 605 are recognized as reductions to Cost of natural gas and natural gas liquids.
- Percent-of-proceeds and percent-of-liquids processing arrangements - Under percent-of-proceeds and percent-of-liquids arrangements within our gathering and processing segment, the Partnership has previously recognized the value of natural gas and natural gas liquids received in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the natural gas and NGLs received

as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the natural gas or NGLs are sold and Product sales are recognized.

- Keep-whole arrangements - Under keep-whole arrangements within our gathering and processing segment, the Partnership has previously recognized the value of NGLs received in Product sales and the value of the thermally equivalent quantity of natural gas provided in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the NGLs received less the value of the thermal equivalent volume of natural gas provided as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the NGLs are sold and Product sales are recognized.

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- Fixed fuel arrangements - Under certain gathering arrangements within our gathering and processing segment as well as under certain transportation arrangements within our transportation and storage segment we receive a fixed amount of fuel regardless of actual fuel usage. Previously, revenue for fuel in excess of actual usage was recognized when such fuel was received, and additional revenue was recognized when such fuel was sold. As of January 1, 2018, fuel in excess of actual usage is treated as a byproduct obtained through the fulfillment of a contract, and the Partnership will recognize revenue at the time the excess fuel is sold. This results in a reduction of Product sales and a corresponding reduction in Cost of natural gas and natural gas liquids.
- Natural gas and natural gas liquids sales arrangements - For certain arrangements within our gathering and processing segment, the Partnership sells the entire hydrocarbon stream at the point of delivery to a third-party processing facility. As of January 1, 2018, these arrangements are considered sales once control has transferred to the third-party processing facility. Therefore, beginning January 1, 2018, the transportation and fractionation fees for these arrangements that were previously recognized as a component of cost of gas and natural gas liquids, are recognized as reductions to the transaction price under ASC 606.

Below is a summary of the impact of the changes on revenues as it relates to the three and six months ended June 30, 2018:

	Three Months Ended June 30, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
	(In millions)		
Revenues:			
Product sales:			
Natural gas	$142	$155	$ (13)
Natural gas liquids	336	344	(8)
Condensate	37	37	—
Total revenues from natural gas, natural gas liquids, and condensate	515	536	(21)
Gain (loss) on derivative activity	(14)	(14)	—
Total Product sales	$501	$522	$ (21)
Service revenues:			
Demand revenues	$165	$165	—
Volume-dependent revenues	139	139	—
Total Service revenues	$304	$304	$ —
Total Revenues	$805	$826	$ (21)

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	Six Months Ended June 30, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
	(In millions)		
Revenues:			
Product sales:			
Natural gas	$270	$294	$ (24)
Natural gas liquids	615	627	(12)
Condensate	73	73	—
Total revenues from natural gas, natural gas liquids, and condensate	958	994	(36)
Gain (loss) on derivative activity	(14)	(14)	—
Total Product sales	$944	$980	$ (36)
Service revenues:			
Demand revenues	$335	$335	—
Volume-dependent revenues	274	273	1
Total Service revenues	$609	$608	$ 1
Total Revenues	$1,553	$1,588	$ (35)

As described above, each of the identified increases/(decreases) in revenue resulted in a corresponding change in the Cost of natural gas and natural gas liquids.

(4) Acquisition

Align Acquisition

On October 4, 2017, the Partnership acquired all of the equity interests in Align Midstream, LLC, a midstream service provider with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin, for approximately $298 million in cash. The acquisition includes approximately 190 miles of natural gas gathering pipelines across Rusk, Panola and Shelby counties in Texas and DeSoto Parish in Louisiana and a cryogenic natural gas processing plant in Panola County, Texas, with a capacity of 100 MMcf/d. The acquisition was accounted for as a business combination and funded with borrowings under the Revolving Credit Facility. During the fourth quarter of 2017, the Partnership finalized the purchase price allocation as of October 4, 2017.

The following table presents the fair value of the identified assets acquired and liabilities assumed at the acquisition date:

Purchase price allocation (in millions):	
Assets acquired:	
Accounts receivable	$5
Property, plant and equipment	111
Intangibles	176
Goodwill	12
Liabilities assumed:	
Current liabilities	6
Total identifiable net assets	$298

In connection with the acquisition, the Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 10 years. Goodwill recognized from the acquisition primarily relates to greater operating leverage in the Ark-La-Tex Basin and is allocated to the gathering and processing segment. The Partnership incurred approximately $2 million of acquisition costs associated with this transaction, which were included in General and administrative expense in the Consolidated Statements of Income in the

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fourth quarter of 2017. The Partnership determined not to include pro forma consolidated financial statements for the periods presented as the impact would not be material.

(5) Earnings Per Limited Partner Unit

The following table illustrates the Partnership's calculation of earnings per unit for common and subordinated units:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions, except per unit data)			
Net income	$95	$96	$209	$216
Net income attributable to noncontrolling interest	—	1	—	1
Series A Preferred Unit distributions	9	9	18	18
General partner interest in net income	—	—	—	—
Net income available to common and subordinated unitholders	$86	$86	$191	$197
Net income allocable to common units	$86	$45	$191	$102
Net income allocable to subordinated units	—	41	—	95
Net income available to common and subordinated unitholders	$86	$86	$191	$197
Net income allocable to common units	$86	$45	$191	$102
Dilutive effect of Series A Preferred Unit distributions	—	—	—	—
Diluted net income allocable to common units	86	45	191	102
Diluted net income allocable to subordinated units	—	41	—	95
Total	$86	$86	$191	$197
Basic weighted average number of outstanding				
Common units (1)	435	225	434	225
Subordinated units	—	208	—	208
Total	435	433	434	433
Basic earnings per unit				
Common units	$0.20	$0.20	$0.44	$0.45
Subordinated units	$—	$0.20	$—	$0.46
Basic weighted average number of outstanding common units	435	225	434	225
Dilutive effect of Series A Preferred Units	—	—	—	—
Dilutive effect of performance units	1	1	1	1
Diluted weighted average number of outstanding common units	436	226	435	226
Diluted weighted average number of outstanding subordinated units	—	208	—	208
Total	436	434	435	434
Diluted earnings per unit				
Common units	$0.20	$0.20	$0.44	$0.45
Subordinated units	$—	$0.20	$—	$0.46

(1) Basic weighted average number of outstanding common units for each of the three and six months ended June 30, 2018 and 2017 includes approximately one million time-based phantom units.

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See Note 6 for discussion of the expiration of the subordination period.

The dilutive effect of the unit-based awards discussed in Note 14 was less than $0.01 per unit during each of the three and six months ended June 30, 2018 and 2017.

(6) Partners' Equity

The Partnership Agreement requires that, within 60 days after the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders, as applicable, during 2017 and 2018 (in millions, except for per unit amounts):

Three Months Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
June 30, 2018 [(1)]	August 21, 2018	August 28, 2018	$ 0.318	$ 138
March 31, 2018	May 22, 2018	May 29, 2018	$ 0.318	$ 138
December 31, 2017	February 20, 2018	February 27, 2018	$ 0.318	$ 138
September 30, 2017	November 14, 2017	November 21, 2017	$ 0.318	$ 138
June 30, 2017	August 22, 2017	August 29, 2017	$ 0.318	$ 138
March 31, 2017	May 23, 2017	May 30, 2017	$ 0.318	$ 137
December 31, 2016	February 21, 2017	February 28, 2017	$ 0.318	$ 137

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on August 1, 2018, to be paid on August 28, 2018, to common unitholders of record at the close of business on August 21, 2018.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2017 and 2018 (in millions, except for per unit amounts):

Three Months Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
June 30, 2018 [(1)]	August 1, 2018	August 14, 2018	$ 0.625	$ 9
March 31, 2018	May 1, 2018	May 15, 2018	$ 0.625	$ 9
December 31, 2017	February 9, 2018	February 15, 2018	$ 0.625	$ 9
September 30, 2017	October 31, 2017	November 14, 2017	$ 0.625	$ 9
June 30, 2017	July 31, 2017	August 14, 2017	$ 0.625	$ 9
March 31, 2017	May 2, 2017	May 12, 2017	$ 0.625	$ 9
December 31, 2016	February 10, 2017	February 15, 2017	$ 0.625	$ 9

(1) The board of directors of Enable GP declared a $0.625 per Series A Preferred Unit cash distribution on August 1, 2018, to be paid on August 14, 2018, to Series A Preferred unitholders of record at the close of business on August 1, 2018.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership

Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units that they own.

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Expiration of Subordination Period

The financial tests required for conversion of all subordinated units were met and the 207,855,430 outstanding subordinated units were converted into common units on a one-for-one basis on August 30, 2017. The conversion of the subordinated units did not change the aggregate amount of outstanding units, and the conversion of the subordinated units did not impact the amount of cash available for distribution by the Partnership.

Series A Preferred Units

On February 18, 2016, the Partnership completed a private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership’s common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;
- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

If and when declared by our general partner, holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis equal to subject to certain adjustments, an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

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ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement, pursuant to which the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. During the six months ended June 30, 2018 and 2017, the Partnership did not issue any common units under the ATM Program.

(7) Investment in Equity Method Affiliate

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence.

SESH is owned 50% by Spectra Energy Partners, LP and 50% by the Partnership. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP may, under certain circumstances, have the right to purchase the Partnership's interest in SESH at fair market value, subject to certain exceptions.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. The Partnership billed SESH $6 million during each of the three months ended June 30, 2018 and 2017, and $8 million and $11 million during the six months ended June 30, 2018 and 2017, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliate under the Other Income (Expense) caption in the Condensed Consolidated Statements of Income for the three and six months ended June 30, 2018 and 2017.

Equity in Earnings of Equity Method Affiliate:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
SESH	$7	$ 7	$13	$ 14

Distributions from Equity Method Affiliate:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
SESH [(1)]	$8	$ 8	$21	$ 19

(1)

Distributions from equity method affiliate includes a $7 million return on investment and a $1 million return of investment for each of the three months ended June 30, 2018 and 2017, respectively. Distributions from equity method affiliate includes a $13 million and $14 million return on investment and a $8 million and $5 million return of investment for the six months ended June 30, 2018 and 2017, respectively.

Summarized financial information of SESH:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Income Statements:				
Revenues	$28	$ 28	$56	$ 56
Operating income	$16	$ 18	$33	$ 35
Net income	$13	$ 13	$25	$ 26

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(8) Debt

The following table presents the Partnership's outstanding debt as of June 30, 2018 and December 31, 2017.

	June 30, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)	Total Debt	Outstanding Principal	Premium (Discount)	Total Debt
	(In millions)					
Commercial Paper	$327	$ —	$327	$405	$ —	$405
Revolving Credit Facility	—	—	—	—	—	—
2015 Term Loan Agreement	—	—	—	450	—	450
2019 Notes	500	—	500	500	—	500
2024 Notes	600	—	600	600	—	600
2027 Notes	700	(3)	697	700	(3)	697
2028 Notes	800	(6)	794	—	—	—
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	10	260	250	13	263
Total debt	$3,727	$ 1	$3,728	$3,455	$ 10	$3,465
Less: Short-term debt (1)			327			405
Less: Current portion of long-term debt (2)			499			450
Less: Unamortized debt expense (3)			21			15
Total long-term debt			$2,881			$2,595

(1) Short-term debt includes $327 million and $405 million of outstanding commercial paper as of June 30, 2018 and December 31, 2017, respectively.

(2) As of June 30, 2018, Current portion of long-term debt includes the $500 million outstanding balance of the 2019 Notes due May 15, 2019, net of approximately $1 million unamortized debt expense. As of December 31, 2017, Current portion of long-term debt includes the $450 million outstanding balance of the 2015 Term Loan Agreement.

(3) As of June 30, 2018 and December 31, 2017, there was an additional $6 million and $3 million, respectively, of unamortized debt expense related to the Revolving Credit Facility included in Other long-term assets, not included above.

Revolving Credit Facility

On April 6, 2018, the Partnership amended and restated its Revolving Credit Facility. As amended and restated, the Revolving Credit Facility is a $1.75 billion, 5-year senior unsecured revolving credit facility, which under certain circumstances may be increased from time to time up to an additional $875 million, in aggregate. The Revolving Credit Facility is scheduled to mature on April 6, 2023, subject to an extension option, which could be exercised two times to extend the term of the Revolving Credit Facility, in each case, for an additional one-year term. As of June 30, 2018, there were no principal advances and $3 million in letters of credit outstanding under the Restated Revolving Credit Facility.

The Revolving Credit Facility provides that outstanding borrowings bear interest at the LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of June 30, 2018, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of June 30, 2018, the commitment fee under the

Restated Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Condensed Consolidated Statements of Income.

Commercial Paper

The Partnership has a commercial paper program, pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There were $327 million and $405 million outstanding under our commercial paper program at June 30, 2018 and December 31, 2017, respectively. The weighted average interest rate for the outstanding commercial paper was 2.76% as of June 30, 2018.

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Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement, providing for an unsecured three-year $450 million term loan agreement, which was scheduled to mature on July 31, 2018. The 2015 Term Loan Agreement is included as Current portion of long-term debt in the Partnership’s Condensed Consolidated Balance Sheets as of December 31, 2017. In May 2018, we used a portion of the proceeds from the issuance of the 2028 Notes to repay all amounts outstanding under the 2015 Term Loan Agreement.

Senior Notes

On May 10, 2018, the Partnership completed the public offering of $800 million aggregate principal amount of its 4.95% Senior Notes due 2028. The Partnership received net proceeds of approximately $787 million. The proceeds were used for general partnership purposes, including to repay all amounts outstanding under the 2015 Term Loan Agreement, as well as amounts outstanding under the commercial paper program. The 2028 Notes had an unamortized discount of $6 million and unamortized debt expense of $7 million at June 30, 2018, resulting in an effective interest rate of 5.20% during the six months ended June 30, 2018.

In addition to the 2028 Notes, as of June 30, 2018, the Partnership’s debt included the 2019 Notes, 2024 Notes, 2027 Notes, and 2044 Notes, which had $14 million of unamortized debt expense at June 30, 2018, resulting in effective interest rates of 2.57%, 4.02%, 4.58% and 5.08%, respectively, during the six months ended June 30, 2018.

As of June 30, 2018, the Partnership’s debt included $250 million aggregate principal amount of EOIT’s 6.25% senior notes due 2020. The EOIT Senior Notes had $10 million of unamortized premium at June 30, 2018, resulting in an effective interest rate of 3.81% during the six months ended June 30, 2018.

As of June 30, 2018, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(9) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership’s commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options, NGL futures and swaps, and WTI crude oil futures and swaps for condensate sales are used to manage the Partnership’s NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership’s natural gas exposure associated with its gathering, processing and transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership’s natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership's gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and are recorded as

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Other Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value on a net basis with such amounts classified as current or long-term based on their anticipated settlement.

As of June 30, 2018 and December 31, 2017, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may seek or be forced to enter into alternative arrangements. In that event, the Partnership's financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership's processing contracts, which are not derivative instruments.

As of June 30, 2018 and December 31, 2017, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	June 30, 2018		December 31, 2017	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas—TBtu[1]				
Financial fixed futures/swaps	19	26	17	13
Financial basis futures/swaps	24	36	17	17
Physical purchases/sales	3	70	1	37
Crude oil (for condensate)—MBbl[2]				
Financial Futures/swaps	—	934	—	564
Natural gas liquids—MBbl[3]				
Financial Futures/swaps	75	2,495	—	1,615

(1) As of June 30, 2018, 81.7% of the natural gas contracts had durations of one year or less, 13.7% had durations of more than one year and less than two years and 4.6% had durations of more than two years. As of December 31, 2017, 67.7% of the natural gas contracts had durations of one year or less, 16.1% had durations of more than one year and less than two years and 16.2% had durations of more than two years.

(2) As of June 30, 2018, 67.9% of the crude oil (for condensate) contracts had durations of one year or less and 32.1% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the crude oil (for

condensate) contracts had durations of one year or less.

(3) As of June 30, 2018, 74.3% of the natural gas liquids contracts had durations of one year or less and 25.7% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the natural gas liquid contracts had durations of one year or less.

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Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Condensed Consolidated Balance Sheets as of June 30, 2018 and December 31, 2017 that were not designated as hedging instruments for accounting purposes are as follows:

		June 30, 2018		December 31, 2017	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current/Other	$2	$ 8	$ 5	$ 4
Physical purchases/sales	Other Current/Other	6	—	3	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current/Other	—	9	—	4
Natural gas liquids					
Financial Futures/swaps	Other Current/Other	1	8	1	5
Total gross derivatives [(1)]		$9	$ 25	$ 9	$ 13

(1) See Note 10 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Condensed Consolidated Balance Sheets as of June 30, 2018 and December 31, 2017.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Condensed Consolidated Statements of Income for the three and six months ended June 30, 2018 and 2017:

	Amounts Recognized in Income			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Natural gas				
Financial futures/swaps (losses) gains	$ (1)	$ 5	$ (5)	$ 16
Physical purchases/sales gains	2	2	5	7
Crude oil (for condensate)				
Financial futures/swaps (losses) gains	(6)	2	(10)	5
Natural gas liquids				
Financial futures/swaps (losses) gains	(9)	—	(4)	2
Total	$ (14)	$ 9	$ (14)	$ 30

For derivatives not designated as hedges in the tables above, amounts recognized in income for the periods ended June 30, 2018 and 2017, if any, are reported in Product sales.

The following table presents the components of gain (loss) on derivative activity in the Partnership's Condensed Consolidated Statements of Income for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Change in fair value of derivatives	$(10)	$11	$(12)	$35
Realized gain (loss) on derivatives	(4)	(2)	(2)	(5)
Gain (loss) on derivative activity	$(14)	$9	$(14)	$30

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Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody’s Investors Services or Standard & Poor’s Ratings Services were to lower the Partnership’s senior unsecured debt rating to a below investment grade rating, the Partnership could be required to provide additional credit assurances to third parties, which could include letters of credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position. As of June 30, 2018, under these obligations, the Partnership has posted $2 million of cash collateral related to NGL and crude swaps and $14 million of additional collateral may be required to be posted by the Partnership in the event of a credit ratings downgrade to a below investment grade rating.

(10) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Condensed Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude oil swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership’s judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership’s own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management’s best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended June 30, 2018, there were no transfers between levels.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor’s Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper and other such financial instruments on the Condensed Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts due to their short-term nature and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership’s financial instruments as of June 30, 2018 and December 31, 2017.

	June 30, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2) (1)	$ —	$ —	$ —	$ —
2015 Term Loan Agreement (Level 2)	—	—	450	450
2019 Notes (Level 2)	500	497	500	497
2024 Notes (Level 2)	600	578	600	602
2027 Notes (Level 2)	697	663	697	712
2028 Notes	794	780	—	—
2044 Notes (Level 2)	550	487	550	550
EOIT Senior Notes (Level 2)	260	259	263	265

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. $327 million and $405 million of commercial paper was outstanding as of June 30, 2018 and December 31, 2017, respectively.

The fair value of the Partnership's Revolving Credit Facility, 2015 Term Loan Agreement, 2019 Notes, 2024 Notes, 2027 Notes, 2028 Notes, 2044 Notes and EOIT Senior Notes is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). As of June 30, 2018, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2018 and December 31, 2017:

June 30, 2018	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities		

			Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$2	$ 6	$ —	$ —
Significant other observable inputs (Level 2)	6	11	15	15
Unobservable inputs (Level 3)	1	8	—	—
Total fair value	9	25	15	15
Netting adjustments	(2)	(2)	—	—
Total	$7	$ 23	$ 15	$ 15

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December 31, 2017	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$5	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	4	5	27	12
Unobservable inputs (Level 3)	—	5	—	—
Total fair value	9	13	27	12
Netting adjustments	(5)	(5)	—	—
Total	$4	$ 8	$ 27	$ 12

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of June 30, 2018 and December 31, 2017.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $14 million and $10 million at June 30, 2018 and December 31, 2017, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created, and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1 million and zero at June 30, 2018 and December 31, 2017, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created, and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following table provides a reconciliation of changes in the fair value of our Level 3 commodity contracts between the periods presented.

	Commodity Contracts
	Natural gas liquids financial futures/swaps
	(In millions)
Balance at December 31, 2017	$ (5)
Losses included in earnings	(4)
Settlements	2
Transfers out of Level 3	—
Balance as of June 30, 2018	$ (7)

Quantitative Information on Level 3 Fair Value Measurements

The Partnership utilizes the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

June 30, 2018

Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$(7)	$0.10 - $1.1113

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(11) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Six Months Ended June 30,	
	2018	2017
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 65	$ 50
Income taxes, net of refunds	1	—
Non-cash transactions:		
Accounts payable related to capital expenditures	42	24

The following table reconciles cash and cash equivalents and restricted cash on the Condensed Consolidated Balance Sheets to cash, cash equivalents and restricted cash on the Condensed Consolidated Statements of Cash Flows:

	Six Months Ended June 30,	
	2018	2017
	(In millions)	
Cash and cash equivalents	$ 7	$ 7
Restricted cash	14	14
Cash, cash equivalents and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 21	$ 21

(12) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy’s LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas. Those services include firm transportation with seasonal contract demand, firm storage, no notice transportation with associated storage and maximum rate firm transportation. Contracts for firm transportation with seasonal contract demand, firm storage, firm no notice transportation with storage for CenterPoint’s LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas are in effect through March 21, 2021 and will remain in effect thereafter unless and until terminated by either party upon 180 days’ prior written notice. Contracts for maximum firm rate transportation for CenterPoint’s LDCs in Oklahoma and portions of Northeast Texas are also in effect through March 21, 2021. Contracts for CenterPoint’s LDCs in Arkansas, Louisiana and Texarkana, Texas terminated on March 31, 2018. MRT provides transportation and storage services to CenterPoint Energy’s LDCs in Arkansas and Louisiana.

Contracts for these services are in effect through May 15, 2023 and will remain in effect thereafter unless and until terminated by either party upon 12 months' prior written notice.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to OGE Energy. On March 17, 2014, EOIT entered into a transportation agreement with OGE Energy, with a primary term of May 1, 2014 through April 30, 2019. Following the primary term, the agreement will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period.

On December 6, 2016, EOIT entered into a transportation agreement with OGE Energy, with a primary term expected to begin in late 2018 and extend for 20 years. In connection with the agreement, an approximately 80-mile pipeline will be built to expand the EOIT system.

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Gas Sales and Purchases Transactions

The Partnership sells natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchases natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. The Partnership enters into these physical natural gas transactions in the normal course of business based upon relevant market prices.

The Partnership's revenues from affiliated companies accounted for 4% and 5% of total revenues during the three months ended June 30, 2018 and 2017, respectively, and 5% and 6% of total revenues during the six months ended June 30, 2018 and 2017, respectively. Amounts of revenues from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Gas transportation and storage service revenues — CenterPoint Energy	$ 24	$ 24	$ 57	$ 57
Natural gas product sales — CenterPoint Energy	2	1	8	1
Gas transportation and storage service revenues — OGE Energy	9	9	18	18
Natural gas product sales — OGE Energy	1	—	2	—
Total revenues — affiliated companies	$ 36	$ 34	$ 85	$ 76

Amounts of natural gas purchased from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Cost of natural gas purchases — CenterPoint Energy	$ —	$ 1	$ 2	$ 1
Cost of natural gas purchases — OGE Energy	5	4	8	7
Total cost of natural gas purchases — affiliated companies	$ 5	$ 5	$ 10	$ 8

Seconded employees, corporate services and operating lease expense

As of June 30, 2018, the Partnership had certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at actual cost subject to a cap of $5 million in 2018 and thereafter, unless and until secondment is terminated.

The Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under services agreements for an initial term that ended on April 30, 2016. The services agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the Partnership may terminate the services agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2018 are $4 million and $1 million, respectively.

The Partnership leases office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease commenced on October 1, 2016 and extends through December 31, 2019. The Partnership expects to incur approximately $3 million in rent and maintenance expenses during the initial term of the lease. As of June 30, 2018, CenterPoint Energy continues to provide office and data center space to the Partnership in Houston, Texas, under the services agreement. During the first quarter of 2018 the Partnership provided notice to Centerpoint Energy of its intent to terminate the provision of office space in Houston, Texas on August 31, 2018.

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Amounts charged to the Partnership by affiliates for seconded employees, an operating lease and corporate services, included primarily in Operation and maintenance and General and administrative expenses in the Partnership's Condensed Consolidated Statements of Income are as follows:

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(In millions)			
Corporate Services — CenterPoint Energy	$ —	$ 1	$ 1	$ 2
Seconded Employee Costs — OGE Energy	7	9	15	16
Corporate Services — OGE Energy	1	1	1	2
Total corporate services and seconded employees expense	$ 8	$ 11	$ 17	$ 20

Series A Preferred Units

On February 18, 2016, the Partnership completed a private placement to CenterPoint Energy of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 6 for further discussion of the Series A Preferred Units.

(13) Commitments and Contingencies

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

On January 1, 2017, the Partnership entered into a 10-year gathering and processing agreement, which became effective on July 1, 2018, with an affiliate of Energy Transfer Partners, LP for 400 MMcf/d of deliveries to the Godley Plant in Johnson County, Texas. As of June 30, 2018, the Partnership estimates the associated 10-year minimum volume commitment fee to be $226 million.

(14) Equity-Based Compensation

The following table summarizes the Partnership's compensation expense for the three and six months ended June 30, 2018 and 2017 related to performance units, restricted units, and phantom units for the Partnership's employees and independent directors:

Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017

	(In millions)			
Performance units	$2	$ 2	$ 5	$ 5
Restricted units	—	1	1	1
Phantom units	1	1	2	2
Total compensation expense	$3	$ 4	$ 8	$ 8

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Units Outstanding

The Partnership periodically grants performance units, restricted units and phantom units to certain employees under the Enable Midstream Partners, LP Long Term Incentive Plan. A summary of the activity for the Partnership’s performance units, restricted units, and phantom units applicable to the Partnership’s employees at June 30, 2018 and changes during 2018 are shown in the following table.

	Performance Units		Restricted Units		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)					
Units Outstanding at December 31, 2017	2,040,407	$ 13.86	222,434	$ 17.87	987,380	$ 11.38
Granted (1)	529,408	17.70	—	—	503,285	14.04
Vested (2)	(401,772)	16.59	(206,066)	17.48	(4,540)	8.87
Forfeited	(62,465)	13.95	(1,366)	16.75	(43,341)	12.40
Units Outstanding at June 30, 2018	2,105,578	$ 14.30	15,002	$ 23.56	1,442,784	$ 12.29
Aggregate Intrinsic Value of Units Outstanding at June 30, 2018	$ 36		$ —		$ 25	

(1) Performance units represents the target number of performance units granted. The actual number of performance units earned, if any, is dependent upon performance and may range from zero percent to 200 percent of the target.

(2) Performance units vested as of June 30, 2018 include 401,772 units from the annual grant, which were approved by the Board of Directors in 2015 and paid out at 200%, or 803,544 units, based on the level of achievement of a performance goal established by the Board of Directors over the performance period.

Unrecognized Compensation Cost

A summary of the Partnership’s unrecognized compensation cost for its non-vested performance units, restricted units, and phantom units, and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	June 30, 2018	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 16	1.41
Restricted Units	—	0.33
Phantom Units	11	1.61
Total	$ 27	

As of June 30, 2018, there were 7,587,153 units available for issuance under the long-term incentive plan.

(15) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies excerpt in the Partnership's audited 2017 consolidated financial statements included in the Annual Report. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing, which primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers, and

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(ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to our producer, power plant, LDC and industrial end-user customers.

Financial data for reportable segments are as follows:

Three Months Ended June 30, 2018	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$465	$ 149	$ (113)	$501
Service revenues	176	128	—	304
Total Revenues	641	277	(113)	805
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	411	147	(114)	444
Operation and maintenance, General and administrative	76	47	—	123
Depreciation and amortization	63	33	—	96
Taxes other than income tax	10	6	—	16
Operating income	$81	$ 44	$ 1	$126
Capital expenditures	$143	$ 42	$ —	$185
Total assets	$9,254	$ 5,681	$ (3,143)	$11,792

Three Months Ended June 30, 2017	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$336	$ 134	$ (116)	$354
Service revenues	144	129	(1)	272
Total Revenues	480	263	(117)	626
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	269	127	(117)	279
Operation and maintenance, General and administrative	75	45	—	120
Depreciation and amortization	55	34	—	89
Taxes other than income tax	9	7	—	16
Operating income	$72	$ 50	$ —	$122
Capital expenditures	$39	$ 48	$ —	$87
Total assets as of December 31, 2017	$9,079	$ 5,616	$ (3,102)	$11,593

(1) See Note 7 for discussion regarding ownership interests in SESH and related equity earnings included in the transportation and storage segment for the three and six months ended June 30, 2018 and 2017.

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Six Months Ended June 30, 2018	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$883	$ 289	$ (228)	$944
Service revenues	349	267	(7)	609
Total Revenues	1,232	556	(235)	1,553
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	769	286	(236)	819
Operation and maintenance, General and administrative	152	93	(1)	244
Depreciation and amortization	125	67	—	192
Taxes other than income tax	20	13	—	33
Operating income	$166	$ 97	$ 2	$265
Capital expenditures	$291	$ 84	$ —	$375
Total assets	$9,254	$ 5,681	$ (3,143)	$11,792

Six Months Ended June 30, 2017	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$687	$ 287	$ (234)	$740
Service revenues	284	270	(2)	552
Total Revenues	971	557	(236)	1,292
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	555	267	(235)	587
Operation and maintenance, General and administrative	145	90	(1)	234
Depreciation and amortization	111	66	—	177
Taxes other than income tax	18	14	—	32
Operating income	$142	$ 120	$ —	$262
Capital expenditures	$90	$ 58	$ —	$148
Total assets as of December 31, 2017	$9,079	$ 5,616	$ (3,102)	$11,593

(1) See Note 7 for discussion regarding ownership interests in SESH and related equity earnings included in the transportation and storage segment for the three and six months ended June 30, 2018 and 2017.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and the related notes included herein and our audited consolidated financial statements for the year ended December 31, 2017, included in our Annual Report. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read “Forward-Looking Statements.” In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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Overview

Enable Midstream Partners, LP is a Delaware limited partnership formed in May 2013 by CenterPoint Energy, OGE Energy and ArcLight to own, operate and develop midstream energy infrastructure assets strategically located to serve our customers. We completed our initial public offering in April 2014, and we are traded on the NYSE under the symbol "ENBL." Our general partner is owned by CenterPoint Energy and OGE Energy. In this report, the terms "Partnership" and "Registrant" as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references t Enable Midstream Partners, LP together with its consolidated subsidiaries.

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Our gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. Our transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers.

Our natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Our crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. Our natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma and our investment in SESH, an interstate pipeline extending from Louisiana to Alabama.

We expect our business to continue to be affected by the key trends included in our Annual Report, as well as the recent developments discussed herein. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Our primary business objective is to increase the cash available for distribution to our unitholders over time while maintaining our financial flexibility. Our business strategies for achieving this objective include capitalizing on organic growth opportunities associated with our strategically located assets, growing through accretive acquisitions, maintaining strong customer relationships to attract new volumes and expand beyond our existing asset footprint and business lines, and continuing to minimize direct commodity price exposure through fee-based contracts. As part of these efforts, we continuously engage in discussions with new and existing customers regarding potential projects to develop new midstream assets to support their needs as well as discussions with potential counterparties regarding opportunities to purchase or invest in complementary assets in new operating areas or midstream business lines. These growth, acquisition and development efforts often involve assets which, if acquired or constructed, could have a material effect on our financial condition and results of operations.

Recent Developments

Regulatory Update

Interstate Natural Gas Transportation Regulation

Effective December 22, 2017, the Tax Cuts and Jobs Act of 2017 changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. FERC issued a Revised Policy

Statement on Treatment of Income Taxes stating that it will no longer permit pipelines organized as master limited partnerships to recover an income tax allowance in their cost-of-service rates. FERC issued the Revised Policy Statement in response to a remand from the U.S. Court of Appeals for the D.C. Circuit in United Airlines v. FERC, in which the court determined that FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not “double recover” its taxes under the current policy by both including an income-tax allowance in its cost-of-service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, FERC issued an order denying requests for rehearing of its Revised Policy Statement because it is a non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors’ income tax costs. The Commission also provided guidance that when a master limited partnership pipeline’s accumulated income tax allowance is eliminated from cost of service, previously accumulated deferred income taxes (ADIT) may also be eliminated as ADIT is not a true-up or tracker of money owed shippers.

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FERC also issued a Notice of Inquiry (NOI) requesting comments on the effect of the Tax Cuts and Jobs Act of 2017 on FERC-jurisdictional rates. The NOI states that of particular interest to FERC is whether, and if so how, FERC should address changes relating to ADIT and bonus depreciation. Comments in response to the NOI were due on or before May 21, 2018. Actions FERC will take, if any, following receipt of responses to the NOI and any potential impacts from final rules or policy statements issued following the NOI on the rates the Partnership can charge for transportation services are unknown at this time, but could impact rates the Partnership is permitted to charge its customers.

Included in the March 15, 2018 issuances is a Notice of Proposed Rulemaking (NOPR) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information. The Final Rule states that this information will allow FERC and other stakeholders to evaluate the impacts of the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement on each individual pipeline’s rates. The Final Rule also requires that each FERC-regulated natural gas pipeline select one of four options: file a limited NGA Section 4 filing reducing its rates only as required in relation to the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the Commission clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. At this time, we cannot predict the outcome of the Final Rule, but FERC’s adoption of the regulation could impact the rates the Partnership is permitted to charge its customers.

Even without action on the NOI or as contemplated in the Final Rule, the FERC or our shippers may challenge the cost of service rates we charge. FERC’s establishment of a just and reasonable rate is based on many components, and tax-related changes will affect tax-related accounts, such as the annual allowance for income taxes and the balance sheet amounts for accumulated deferred income taxes and related regulatory assets and liabilities, while other pipeline costs also will continue to affect FERC’s determination of just and reasonable cost-of-service rates. Although changes in these tax-related accounts may vary, other components in the cost-of-service rate calculation may also change and result in a newly calculated cost-of-service rate that is the same as or greater than the prior cost-of-service rate. Moreover, pipelines receive revenues from cost-of-service rates, negotiated rates, discounted rates, and market-based rates, or a combination thereof. As of December 31, 2017, approximately 62% of our aggregate contracted firm transportation capacity on EGT was subscribed under negotiated rate contracts and approximately 100% of our aggregate contracted firm storage capacity on EGT was subscribed under negotiated rate contracts. As of December 31, 2017, our aggregate contracted firm transportation capacity and our aggregated contracted firm storage capacity on MRT was not subscribed under negotiated rate contracts. As of December 31, 2017, approximately 23% and 41% of our aggregate contracted firm transportation capacity on EGT and MRT, respectively, was subscribed under discounted rate contracts. We do not expect rates subject to negotiated rates that are not tied to the cost-of-service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 issuances. Nor will discounted rates which are below the level of any new maximum rate be affected. With respect to the cost-of-service rates, depending on a detailed review of all of the Partnership’s cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers, the NOI, the Final Rule, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Cuts and Jobs Act of 2017, the revenues associated with natural gas transportation services we provide pursuant to cost-of-service based rates may decrease in the future.

The FERC issued a Notice of Inquiry on April 19, 2018 (April 2018 NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the April 2018 NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would materially affect our plans and operations.

MRT Rate Case

On June 29, 2018, MRT filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act. The rate case proposed, among other things, a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by MRT, a change in the boundary between the Field and Market zones, a requirement for daily balancing, and changes to the Small Customer service rate schedule. A number of customers filed notices of intervention and protests, and on July 31, 2018, FERC issued an Order Accepting and Suspending Tariff Records Subject to Refund and Condition and Establishing Hearing and Settlement Judge Procedures and a Technical Conference (July 31 Order). In the July 31 Order, the Commission ordered MRT to refile its rate case within 30 days of the date of the July 31 Order to reflect, among other things, the elimination of an income tax allowance from its costs used to calculate MRT's rates. When coupled with the corresponding elimination of ADIT, as discussed above, management believes the impact will not be material to the MRT cost-of-service previously filed.

Interstate Crude Oil Transportation Regulation

FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23%. Many existing pipelines, including our Williston Basin crude oil gathering systems, utilize the FERC oil index to change transportation rates annually every July 1. With respect to oil and refined products pipelines subject to FERC jurisdiction, the Revised Policy Statement requires the pipeline to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 on the Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 in the determination of indexed rates prospectively, effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act of 2017 may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates.

Imposition of Ad Valorem Tariffs

The construction of pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to costs and availability of equipment and materials such as steel. If third party providers of steel products essential to our capital improvements and additions are unable to obtain raw materials, including steel, at historical prices, they may raise the price we pay for such products. On March 8, 2018, the President issued two proclamations directing the imposition of ad valorem tariffs of 25 percent on certain imported steel products and 10 percent on certain imported aluminum products. Following these proclamations, certain countries have been granted tariff exemptions for steel imports, and in certain cases, a quota system rather than tariffs has been implemented. Additionally, domestic prices for steel have risen and are expected to continue to rise. While steel pipe costs relating to our previously announced projects are fixed for 2018, the price increases may result in increased costs associated with the continued build-out of our gathering systems as well as projects under development. If we are not able to pass these cost increases along to our customers, our income from operations and cash flows may be adversely affected.

Commercial and Construction Update

Project Wildcat rich gas takeaway solution

Project Wildcat, which provides access for approximately 400 MMcf/d of rich natural gas from the Anadarko Basin to North Texas, was placed into service during June 2018 and achieved full operational capacity in July 2018. This rich gas is able to reach the Texas intrastate natural gas markets, including the Tolar Hub, by being processed under the Partnership's agreement with an affiliate of Energy Transfer Partners, LP for 400 MMcf/d of firm processing capacity at the Godley Plant in Johnson County, Texas. Even with the 400 MMcf/d of processing capacity provided by this project, the Partnership anticipates that there will be a need to resume construction of the previously announced Wildhorse Plant, a 200 MMcf/d cryogenic processing facility we plan to connect to our super-header system in Garvin County, Oklahoma, though likely not before 2019.

EGT and EOIT Expansion Projects

Newfield Exploration Company has entered into a 205,000 Dth/d firm natural gas transportation agreement with EGT related to the Cana and STACK Expansion (CaSE) project, a system expansion providing firm transportation service for growing Anadarko Basin production. The 10-year contract started at an initial capacity of 45,000 Dth/d in early 2018, achieved a contractual increase in volumes to 135,000 Dth/d in the second quarter of 2018, and is expected to grow to the full contracted capacity by the end of the fourth quarter of 2018. The Muskogee project, a 20-year, 228,000 Dth/d firm transportation service agreement with a subsidiary of OGE Energy on the EOIT system, is expected to commence service by the end of the fourth quarter of 2018.

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CenterPoint Strategic Review

CenterPoint Energy has publicly disclosed that it has evaluated various strategic alternatives for its investment in the Partnership, including a sale or spin-off qualifying under Section 355 of the U.S. Internal Revenue Code, but has decided not to pursue any such alternatives because the alternatives would not achieve CenterPoint Energy's objectives. CenterPoint Energy has also publicly disclosed that it may reduce its ownership of the common units it holds in the Partnership over time through sales in the public equity markets, or otherwise, subject to market conditions. CenterPoint Energy has also publicly said it may pursue a transaction for all of CenterPoint Energy's interest in the Partnership if such a transaction becomes viable in the future. There can be no assurances that these evaluations and announcements will result in any specific action.

Liquidity Update

Second Amended and Restated Revolving Credit Facility

On April 6, 2018, the Partnership amended and restated the Revolving Credit Facility in its entirety. For more information, please see Note 8 of the Notes to Condensed Consolidated Financial Statements.

2028 Notes

On May 10, 2018, the Partnership completed the public offering of $800 million aggregate principal amount of its 4.95% Senior Notes due 2028. For more information, please see Note 8 of the Notes to Condensed Consolidated Financial Statements.

Results of Operations

The following tables summarize the key components of our results of operations for the three and six months ended June 30, 2018 and 2017.

Three Months Ended June 30, 2018	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$465	$ 149	$ (113)	$ 501
Service revenues	176	128	—	304
Total Revenues	641	277	(113)	805
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	411	147	(114)	444
Gross margin [(1)]	230	130	1	361
Operation and maintenance, General and administrative	76	47	—	123
Depreciation and amortization	63	33	—	96
Taxes other than income tax	10	6	—	16
Operating income	$81	$ 44	$ 1	$ 126
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

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Three Months Ended June 30, 2017	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$336	$ 134	$ (116)	$ 354
Service revenues	144	129	(1)	272
Total Revenues	480	263	(117)	626
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	269	127	(117)	279
Gross margin (1)	211	136	—	347
Operation and maintenance, General and administrative	75	45	—	120
Depreciation and amortization	55	34	—	89
Taxes other than income tax	9	7	—	16
Operating income	$72	$ 50	$ —	$ 122
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

Six Months Ended June 30, 2018	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$883	$ 289	$ (228)	$ 944
Service revenues	349	267	(7)	609
Total Revenues	1,232	556	(235)	1,553
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	769	286	(236)	819
Gross margin (1)	463	270	1	734
Operation and maintenance, General and administrative	152	93	(1)	244
Depreciation and amortization	125	67	—	192
Taxes other than income tax	20	13	—	33
Operating income	$166	$ 97	$ 2	$ 265
Equity in earnings of equity method affiliate	$—	$ 13	$ —	$ 13

Six Months Ended June 30, 2017	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$687	$ 287	$ (234)	$ 740
Service revenues	284	270	(2)	552
Total Revenues	971	557	(236)	1,292
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	555	267	(235)	587
Gross margin (1)	416	290	(1)	705
Operation and maintenance, General and administrative	145	90	(1)	234
Depreciation and amortization	111	66	—	177
Taxes other than income tax	18	14	—	32
Operating income	$142	$ 120	$ —	$ 262
Equity in earnings of equity method affiliate	$—	$ 14	$ —	$ 14

(1)

Gross margin is a non-GAAP measure and is reconciled to its most directly comparable financial measures calculated and presented below under the caption Reconciliations of Non-GAAP Financial Measures.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Operating Data:				
Gathered volumes—TBtu	403	301	788	597
Gathered volumes—TBtu/d	4.43	3.31	4.35	3.30
Natural gas processed volumes—TBtu	212	174	412	342
Natural gas processed volumes—TBtu/d	2.33	1.91	2.27	1.89
NGLs produced—MBbl/d (1)	130.65	87.12	120.44	83.46
NGLs sold—MBbl/d (1)(2)	130.07	86.51	119.79	82.61
Condensate sold—MBbl/d	6.72	5.04	6.84	5.26
Crude Oil—Gathered volumes—MBbl/d	30.55	23.20	27.70	22.19
Transported volumes—TBtu	473	445	983	938
Transported volumes—TBtu/d	5.16	4.86	5.41	5.17
Interstate firm contracted capacity—Bcf/d	5.72	6.21	5.89	6.72
Intrastate average deliveries—TBtu/d	1.88	1.84	1.92	1.84

(1) Excludes condensate.
(2) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Anadarko				
Gathered volumes—TBtu/d	2.14	1.78	2.08	1.77
Natural gas processed volumes—TBtu/d	1.91	1.58	1.87	1.56
NGLs produced—MBbl/d (1)	113.75	74.14	104.77	70.74
Arkoma				
Gathered volumes—TBtu/d	0.56	0.54	0.55	0.55
Natural gas processed volumes—TBtu/d	0.11	0.09	0.10	0.09
NGLs produced—MBbl/d (1)	7.60	4.60	6.29	4.72
Ark-La-Tex				
Gathered volumes—TBtu/d	1.73	0.99	1.72	0.98
Natural gas processed volumes—TBtu/d	0.31	0.24	0.30	0.24
NGLs produced—MBbl/d (1)	9.30	8.38	9.38	8.00

(1) Excludes condensate.

Gathering and Processing

Three months ended June 30, 2018 compared to three months ended June 30, 2017. Our gathering and processing segment reported operating income of $81 million for the three months ended June 30, 2018 compared to operating income of $72 million for the three months ended June 30, 2017. The difference of $9 million in operating income between periods was primarily due to a $19 million increase in gross margin. This was partially offset by an $8 million increase in depreciation and amortization, a $1 million increase in operation and maintenance and general and administrative expenses, and a $1 million increase in taxes other than income tax during the three months ended June 30, 2018.

Our gathering and processing segment revenues increased $161 million. The increase was primarily due to the following:

Product Sales:

- revenues from NGL sales increased $151 million resulting from higher average NGL prices, higher processed volumes and higher plant recoveries of ethane in the Anadarko and Ark-La-Tex Basins, inclusive of an $8 million decrease due to the implementation of ASC 606.

This increase was partially offset by:

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- changes in the fair value of natural gas, condensate and NGL derivatives decreased $16 million, and
- revenues from natural gas sales decreased $5 million primarily due to a $11 million decrease related to the implementation of ASC 606 and a $5 million increase due to higher sales volumes.

Service Revenues:

- processing service revenues increased $25 million resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex Basins, inclusive of a $11 million increase due to the implementation of ASC 606,
- natural gas gathering revenues increased $5 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of an $11 million decrease due to the implementation of ASC 606, and
- crude oil and water gathering revenues increased $2 million due to an increase in gathered volumes partially offset by a reduction in average rates.

Our gathering and processing segment gross margin increased $19 million. The increase was primarily due to the following:

- processing service fees increased $25 million from higher processed volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $12 million increase due to the implementation of ASC 606,
- natural gas gathering fees increased $5 million due to increased gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of an $11 million decrease due to the implementation of ASC 606,
- crude oil and water gathering fees increased $2 million due to an increase in gathered volumes partially offset by a reduction in average rates,
- revenues from natural gas sales less the cost of natural gas increased $3 million primarily due to a $21 million increase due to higher sales volumes, a $9 million change in imbalance volumes owed customers and a $9 million increase in fuel costs, inclusive of an $11 million increase due to the implementation of ASC 606, and
- revenues from NGL sales less the cost of NGLs increased $1 million resulting from higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $12 million decrease due to the implementation of ASC 606.

These increases were partially offset by a decrease in the changes in the fair value of natural gas, condensate and NGL derivatives of $16 million.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $1 million. The increase was primarily due to a $4 million increase in materials and supplies and contract services expense as a result of additional assets in service, a $3 million increase in expenses related to maintenance on treating plants as a result of increased activity on our Ark-La-Tex assets, a $2 million increase in compressor rental expenses due to increased rental units, and a $1 million increase in payroll-related costs. These increases were partially offset by a $5 million decrease due to a loss on the disposal of assets in the second quarter of 2017, for which there were no comparable items in the second quarter of 2018, a $3 million decrease due to an increase in capitalized overhead costs as a result of an increase in capital projects in the second quarter of 2018 and a $1 million change in the allowance for doubtful accounts due to the collection of accounts receivable in the three months ended June 30, 2018 that were previously included in the allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization increased $8 million due to additional assets placed in service primarily as a result of the Align Midstream, LLC acquisition in the fourth quarter of 2017.

Our gathering and processing segment taxes other than income tax increased $1 million due to higher accrued ad valorem taxes due to additional assets placed in service.

Six months ended June 30, 2018 compared to six months ended June 30, 2017. Our gathering and processing segment reported operating income of $166 million for the six months ended June 30, 2018 compared to operating income of

$142 million for the six months ended June 30, 2017. The difference of $24 million in operating income between periods was primarily due to a $47 million increase in gross margin. This was partially offset by a $7 million increase in operation and maintenance and general and administrative expenses, a $14 million increase in depreciation and amortization and a $2 million increase in taxes other than income tax during the six months ended June 30, 2018.

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Our gathering and processing segment revenues increased $261 million. The increase was primarily due to the following:

Product Sales:

- revenues from NGL sales increased $232 million resulting from higher average NGL prices, higher processed volumes and higher plant recoveries of ethane in the Anadarko and Ark-La-Tex Basins, inclusive of a $12 million decrease due to the implementation of ASC 606.

These increases were partially offset by:

- changes in the fair value of natural gas, condensate and NGL derivatives decreased $23 million, and
- revenues from natural gas sales decreased $13 million due to a $22 million decrease related to the implementation of ASC 606 and an $8 million increase due to higher sales volumes.

Service Revenues:

- processing service revenues increased $55 million resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex basis, inclusive of a $24 million increase due to the implementation of ASC 606,
- natural gas gathering revenues increased $7 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $23 million decrease due to the implementation of ASC 606, and
- crude oil and water gathering revenues increased $3 million due to an increase in gathered volumes partially offset by a reduction in average rates.

Our gathering and processing segment gross margin increased $47 million. The increase was primarily due to the following:

- processing service fees increased $55 million due to higher processed volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $24 million increase due to the implementation of ASC 606,
- natural gas gathering fees increased $7 million due to increased gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $23 million decrease due to the implementation of ASC 606,
- revenues from natural gas sales less the cost of natural gas increased $6 million primarily due to a $22 million increase due to higher sales volumes, an $11 million change in imbalance volumes owed customers and a $5 million increase in fuel costs, inclusive of a $23 million increase due to the implementation of ASC 606, and
- crude oil and water gathering fees increased $3 million due to an increase in gathered volumes partially offset by a reduction in average rates.

These increases were partially offset by:

- changes in the fair value of natural gas, condensate and NGL derivatives decreased $23 million, and
- revenues from NGL sales less the cost of NGLs decreased $1 million due to higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $24 million decrease due to the implementation of ASC 606.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $7 million. The increase was primarily due to a $5 million increase in expenses related to maintenance on treating plants as a result of increased activity on our Ark-La-Tex assets, $4 million increase in payroll-related costs, a $4 million increase in compressor rental expenses due to increased rental units and a $4 million increase in materials and supplies and contract services expense as a result of additional assets in service. These were partially offset by a $5 million decrease due to a loss on the disposal of assets in the second quarter of 2017, for which there were no comparable items in the second quarter of 2018, a $4 million decrease due to an increase in capitalized overhead costs as a result of an increase in projects in 2018 and a $1 million change in the allowance for doubtful accounts due to the collection of accounts receivable in the six months ended June 30, 2018 that were previously included in the allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization increased $14 million due to additional assets placed in service primarily as a result of the Align Midstream, LLC acquisition in the fourth quarter of 2017.

Our gathering and processing segment taxes other than income tax increased $2 million due to higher accrued ad valorem taxes due to additional assets placed in service.

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Transportation and Storage

Three months ended June 30, 2018 compared to three months ended June 30, 2017. Our transportation and storage segment reported operating income of $44 million for the three months ended June 30, 2018 compared to operating income of $50 million for the three months ended June 30, 2017. The difference of $6 million in operating income between periods was primarily due to a $6 million decrease in gross margin and a $2 million increase in operation and maintenance and general and administrative expenses, partially offset by a $1 million decrease in depreciation and amortization and a $1 million decrease in taxes other than income tax for the three months ended June 30, 2018.

Our transportation and storage segment revenues increased $14 million. The increase was primarily due to the following:

Product Sales:

- revenues from natural gas sales increased $20 million primarily due to higher sales volumes, inclusive of a $2 million decrease due to the implementation of ASC 606.

These increases were partially offset by a decrease in the changes in the fair value of natural gas derivatives of $5 million.

Service Revenues:

- other firm transportation and storage services increased $3 million due to new intrastate transportation contracts, and
- volume-dependent transportation revenues increased $1 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates.

These increases were partially offset by:

- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $5 million due to contract expirations since the second quarter of 2017.

Our transportation and storage segment gross margin decreased $6 million. The decrease was primarily due to the following:

- changes in the fair value of natural gas derivatives decreased $5 million,
- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $5 million due to contract expirations in the second quarter of 2017.

These decreases were partially offset by:

- other firm transportation and storage services increased $3 million due to new intrastate transportation contracts, and
- volume-dependent transportation increased $1 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $2 million. The increase was primarily due to a $1 million increase in payroll-related costs and a $2 million increase in materials and supplies and contract services expense. These increases were partially offset by a $1 million decrease due to increased capitalized overhead costs.

Our transportation and storage segment depreciation and amortization decreased $1 million due to an acceleration of depreciation expense in the three months ended June 30, 2017.

Six months ended June 30, 2018 compared to six months ended June 30, 2017. Our transportation and storage segment reported operating income of $97 million for the six months ended June 30, 2018 compared to operating income of $120 million for the six months ended June 30, 2017. The difference of $23 million in operating income between periods was primarily due to a $20 million decrease in gross margin, a $3 million increase in operation and maintenance and general and administrative expenses, and a $1 million increase in depreciation and amortization, partially offset by a $1 million decrease in taxes other than income for the six months ended June 30, 2018.

Our transportation and storage segment revenues decreased $1 million. The decrease was primarily due to the following:

Product Sales:

- changes in the fair value of natural gas derivatives decreased $24 million.

These decreases were partially offset by:

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- revenues from natural gas sales increased $25 million primarily due to higher sales volumes, inclusive of a $2 million decrease due to the implementation of ASC 606, and
- revenues from NGL sales increased $1 million due to an increase in prices.

Service Revenues:

- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $17 million due to contract expirations since the second quarter of 2017.

These decreases were partially offset by:

- volume-dependent transportation revenues increased $9 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates, and
- other firm transportation and storage services increased $5 million due to new intrastate transportation contracts.

Our transportation and storage segment gross margin decreased $20 million. The decrease was primarily due to the following:

- changes in the fair value of natural gas derivatives decreased $24 million, and
- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $17 million due to contract expirations since the second quarter of 2017.

These decreases were partially offset by:

- volume-dependent transportation increased $9 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates,
- system management activities increased $7 million, and
- other firm transportation and storage services increased $5 million due to new intrastate transportation contracts.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $3 million. The increase was primarily due to a $2 million increase in payroll-related costs, a $2 million increase in materials and supplies and contract services expenses, and a $1 million increase in one-time reimbursements associated with an unplanned pipeline outage. These increases were partially offset by a $2 million decrease due to increased capitalized overhead costs.

Our transportation and storage segment depreciation and amortization increased $1 million due to additional assets placed in service.

Condensed Consolidated Interim Information

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Operating Income	$126	$122	$265	$262
Other Income (Expense):				
Interest expense	(36)	(31)	(69)	(58)
Equity in earnings of equity method affiliate	7	7	13	14
Other, net	(2)	(1)	—	—
Total Other Expense	(31)	(25)	(56)	(44)
Income Before Income Taxes	95	97	209	218
Income tax expense	—	1	—	2
Net Income	$95	$96	$209	$216

Less: Net income attributable to noncontrolling interest	—	1	—	1
Net Income Attributable to Limited Partners	$95	$95	$209	$215
Less: Series A Preferred Unit distributions	9	9	18	18
Net Income Attributable to Common and Subordinated Units	$86	$86	$191	$197

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Three Months Ended June 30, 2018 compared to Three Months Ended June 30, 2017

Net Income attributable to limited partners. Net income attributable to limited partners remained flat at $95 million in the three months ended June 30, 2018 compared to the three months ended June 30, 2017. Net income attributable to limited partners of $95 million was primarily attributable to an increase in operating income of $4 million offset by an increase in interest expense of $5 million in the three months ended June 30, 2018.

Interest Expense. Interest expense increased $5 million primarily due to an increase in the amount of debt outstanding as well as higher interest rates on the Partnership's outstanding debt as a result of a long-term debt issuance in May 2018 that resulted in the repayment of amounts outstanding under the Partnership's 2015 Term Loan Agreement, as well as amounts outstanding under our commercial paper program.

Six Months Ended June 30, 2018 compared to Six Months Ended June 30, 2017

Net Income attributable to limited partners. We reported net income attributable to limited partners of $209 million in the six months ended June 30, 2018 compared to net income attributable to limited partners of $215 million in the six months ended June 30, 2017. The decrease in net income attributable to limited partners of $6 million was primarily attributable to an increase in interest expense of $11 million in the six months ended June 30, 2018.

Interest Expense. Interest expense increased $11 million primarily due to an increase in the amount of debt outstanding as well as higher interest rates on the Partnership's outstanding debt as a result of a long-term debt issuance in May 2018 that resulted in the repayment of amounts outstanding under the Partnership's 2015 Term Loan Agreement, as well as amounts outstanding under our commercial paper program.

Reconciliations of Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio in this report based on information in its condensed consolidated financial statements. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are part of the performance measures that we use to manage the Partnership.

Provided below are reconciliations of Gross margin to total revenues, Adjusted EBITDA and DCF to net income attributable to limited partners, and Adjusted EBITDA to net cash provided by operating activities and Adjusted interest expense to interest expense, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio should not be considered as alternatives to net income, operating income, total revenues, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. These non-GAAP financial measures have important limitations as analytical tools because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in the Partnership's industry, these measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Reconciliation of Gross margin to Total Revenues:				
Consolidated				
Product sales	$501	$354	$944	$740
Service revenues	304	272	609	552
Total Revenues	805	626	1,553	1,292
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	444	279	819	587
Gross margin	$361	$347	$734	$705
Reportable Segments				
Gathering and Processing				
Product sales	$465	$336	$883	$687
Service revenues	176	144	349	284
Total Revenues	641	480	1,232	971
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	411	269	769	555
Gross margin	$230	$211	$463	$416
Transportation and Storage				
Product sales	$149	$134	$289	$287
Service revenues	128	129	267	270
Total Revenues	277	263	556	557
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	147	127	286	267
Gross margin	$130	$136	$270	$290

The following table shows the components of our gross margin for the six months ended June 30, 2018:

	Fee-Based [(1)]			
	Demand	Volume-Dependent	Commodity-Based [(1)]	Total
Six Months Ended June 30, 2018				
Gathering and Processing Segment	22%	53 %	25%	100%
Transportation and Storage Segment	86%	13 %	1 %	100%
Partnership Weighted Average	46%	38 %	16%	100%

(1) For purposes of this table, the Partnership includes the value of all natural gas and NGL commodities received as payment as commodity-based.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions, except Distribution coverage ratio)			
Reconciliation of Adjusted EBITDA and DCF to net income attributable to limited partners and calculation of Distribution coverage ratio:				
Net income attributable to limited partners	$95	$95	$209	$215
Depreciation and amortization expense	96	89	192	177
Interest expense, net of interest income	36	31	69	58
Income tax expense	—	1	—	2
Distributions received from equity method affiliate in excess of equity earnings	1	1	8	5
Non-cash equity-based compensation	3	4	8	8
Change in fair value of derivatives	10	(11)	12	(35)
Other non-cash losses [1]	4	5	4	6
Adjusted EBITDA	$245	$215	$502	$436
Series A Preferred Unit distributions [2]	(9)	(9)	(18)	(18)
Distributions for phantom and performance units [3]	(1)	(1)	(4)	(1)
Adjusted interest expense [4]	(38)	(32)	(73)	(59)
Maintenance capital expenditures	(26)	(17)	(40)	(31)
DCF	$171	$156	$367	$327
Distributions related to common and subordinated unitholders [5]	$138	$138	$276	$275
Distribution coverage ratio	1.24	1.13	1.33	1.19

(1) Other non-cash losses includes loss on sale of assets and write-downs of materials and supplies.

(2) This amount represents the quarterly cash distributions on the Series A Preferred Units declared for the three and six months ended June 30, 2018 and 2017. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made.

(3) Distributions for phantom and performance units represent distribution equivalent rights paid in cash. Phantom unit distribution equivalent rights are paid during the vesting period and performance unit distribution equivalent rights are paid at vesting.

(4) See below for a reconciliation of Adjusted interest expense to Interest expense.

(5) Represents cash distributions declared for common and subordinated units outstanding as of each respective period. Amounts for 2018 reflect estimated cash distributions for common units outstanding for the quarter ended June 30, 2018.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:				
Net cash provided by operating activities	$239	$226	$405	$382
Interest expense, net of interest income	36	31	69	58
Net income attributable to noncontrolling interest	—	(1)		