Enable Midstream Partners, LP
Form 10-Q
August 01, 2017
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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 AND EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017
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 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)

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

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 14, 2017, there were 224,702,072 common units and 207,855,430 subordinated 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; and
- news and other announcements that we may post from time to time that investors may find useful or interesting.

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

Adjusted EBITDA.	A non-GAAP measure calculated as net income attributable to limited partners plus depreciation and amortization expense, interest expense, income tax expense, distributions received from equity method affiliate in excess of equity earnings, non-cash equity-based compensation, impairments, changes in fair value of derivatives, noncontrolling interest share of Adjusted EBITDA and certain other non-cash gains and losses (including gains and losses on sales of assets and write-downs of materials and supplies).
Adjusted interest expense.	A non-GAAP measure calculated as interest expense plus amortization of premium on long-term debt and capitalized interest, less amortization of debt expense and discount.
Annual Report.	Annual Report on Form 10-K for the year ended December 31, 2016.
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.
ASU.	Accounting Standards Update.
ATM Program.	ATM Equity Offering Sales Agreement entered into on May 12, 2017 in connection with an at-the-market program, under which the Partnership may issue and sell common units 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.
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.
CERC.	CenterPoint Energy Resources Corp., a Delaware corporation.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
DCF.	A non-GAAP measure calculated as Adjusted EBITDA, as further adjusted for Series A Preferred Unit distributions, 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 and subordinated units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common or subordinated units.
EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 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 a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.

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.

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General Partner.	Enable GP, LLC, a Delaware limited liability company, the general partner of Enable Midstream Partners, LP.
Gross margin.	A non-GAAP measure calculated as Total revenues minus cost of natural gas and natural gas liquids, excluding depreciation and amortization.
IPO.	Initial public offering of Enable Midstream Partners, LP.
LDC.	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area.
LIBOR.	London Interbank Offered Rate.
MBbl.	Thousand barrels.
MBbl/d.	Thousand barrels per day.
MFA.	Master Formation Agreement dated as of March 14, 2013.
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.	Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of June 22, 2016.
Revolving Credit Facility.	$1.75 billion senior unsecured revolving credit facility.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
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.
2015 Term Loan Agreement.	$450 million unsecured term loan agreement.
2019 Notes.	$500 million 2.400% senior notes due 2019.
2024 Notes.	$600 million 3.900% senior notes due 2024.
2027 Notes.	$700 million 4.400% senior notes due 2027.
2044 Notes.	$550 million 5.000% senior notes due 2044.

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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, the termination of the subordination period 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 this report and in our Annual Report on Form 10-K for the year ended December 31, 2016. Those risk factors and other factors noted throughout this report and in our Annual 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 our General Partner;
- 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;
- 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.

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,	
	2017	2016	2017	2016
	(In millions, except per unit data)			
Revenues (including revenues from affiliates (Note 11)):				
Product sales	$354	$266	$740	$511
Service revenue	272	263	552	527
Total Revenues	626	529	1,292	1,038
Cost and Expenses (including expenses from affiliates (Note 11)):				
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	279	254	587	449
Operation and maintenance	97	93	186	188
General and administrative	23	27	48	47
Depreciation and amortization	89	83	177	164
Taxes other than income taxes	16	15	32	30
Total Cost and Expenses	504	472	1,030	878
Operating Income	122	57	262	160
Other Income (Expense):				
Interest expense (including expenses from affiliates (Note 11))	(31)	(25)	(58)	(48)
Equity in earnings of equity method affiliate	7	7	14	14
Other, net	(1)	—	—	—
Total Other Expense	(25)	(18)	(44)	(34)
Income Before Income Taxes	97	39	218	126
Income tax expense	1	—	2	1
Net Income	$96	$39	$216	$125
Less: Net income attributable to noncontrolling interest	1	—	1	—
Net Income Attributable to Limited Partners	$95	$39	$215	$125
Less: Series A Preferred Unit distributions (Note 4)	9	4	18	4
Net Income Attributable to Common and Subordinated Units (Note 3)	$86	$35	$197	$121
Basic earnings per unit (Note 3)				
Common units	$0.20	$0.08	$0.45	$0.29
Subordinated units	$0.20	$0.08	$0.46	$0.29
Diluted earnings per unit (Note 3)				
Common units	$0.20	$0.08	$0.45	$0.28
Subordinated units	$0.20	$0.08	$0.46	$0.29

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

	June 30, 2017	December 31, 2016
	(In millions)	
Current Assets:		
Cash and cash equivalents	$7	$ 6
Restricted cash	14	17
Accounts receivable, net of allowance for doubtful accounts	220	249
Accounts receivable—affiliated companies	14	13
Inventory	42	41
Gas imbalances	23	41
Other current assets	31	29
Total current assets	351	396
Property, Plant and Equipment:		
Property, plant and equipment	11,699	11,567
Less accumulated depreciation and amortization	1,571	1,424
Property, plant and equipment, net	10,128	10,143
Other Assets:		
Intangible assets, net	293	306
Investment in equity method affiliate	324	329
Other	35	38
Total other assets	652	673
Total Assets	$11,131	$ 11,212
Current Liabilities:		
Accounts payable	$140	$ 181
Accounts payable—affiliated companies	3	3
Taxes accrued	38	30
Gas imbalances	9	35
Other	108	113
Total current liabilities	298	362
Other Liabilities:		
Accumulated deferred income taxes, net	11	10
Regulatory liabilities	20	19
Other	34	34
Total other liabilities	65	63
Long-Term Debt	3,046	2,993
Commitments and Contingencies (Note 12)		
Partners’ Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at June 30, 2017 and December 31, 2016)	362	362
Common units (224,700,966 issued and outstanding at June 30, 2017 and 224,535,454 issued and outstanding at December 31, 2016, respectively)	3,702	3,737
Subordinated units (207,855,430 issued and outstanding at June 30, 2017 and December 31, 2016, respectively)	3,646	3,683
Noncontrolling interest	12	12
Total Partners’ Equity	7,722	7,794
Total Liabilities and Partners’ Equity	$11,131	$ 11,212

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,	
	2017	2016
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$216	$125
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	177	164
Deferred income taxes	2	—
Loss on sale/retirement of assets	5	7
Equity in earnings of equity method affiliate	(14)	(14)
Return on investment in equity method affiliate	14	14
Equity-based compensation	8	5
Amortization of debt costs and discount (premium)	(1)	(1)
Changes in other assets and liabilities:		
Accounts receivable, net	29	20
Accounts receivable—affiliated companies	(1)	2
Inventory	(1)	9
Gas imbalance assets	18	4
Other current assets	(2)	(1)
Other assets	3	1
Accounts payable	(46)	(79)
Accounts payable—affiliated companies	—	(5)
Gas imbalance liabilities	(26)	(15)
Other current liabilities	3	48
Other liabilities	(2)	5
Net cash provided by operating activities	382	289
Cash Flows from Investing Activities:		
Capital expenditures	(148)	(221)
Proceeds from sale of assets	1	—
Return of investment in equity method affiliate	5	13
Net cash used in investing activities	(142)	(208)
Cash Flows from Financing Activities:		
Proceeds from long term debt, net of issuance costs	691	—
Proceeds from revolving credit facility	394	693
Repayment of revolving credit facility	(1,030)	(261)
Decrease in short-term debt	—	(236)
Repayment of notes payable—affiliated companies	—	(363)
Proceeds from issuance of Series A Preferred Units, net of issuance costs	—	362
Distributions	(296)	(274)
Cash taxes paid for employee equity-based compensation	(1)	—
Net cash used in financing activities	(242)	(79)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(2)	2
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	23	4

Cash, Cash Equivalents and Restricted Cash at End of Period	$21	$6

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, 2015	—	$—	214	$3,714	208	$3,805	$ 12	$7,531
Net income	—	4	—	62	—	59	—	125
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Distributions	—	(4)	—	(137)	—	(132)	(1)	(274)
Equity-based compensation, net of units for employee taxes	—	—	—	5	—	—	—	5
Balance as of June 30, 2016	15	$362	214	$3,644	208	$3,732	$ 11	$7,749
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

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) 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, 2017, CenterPoint Energy held approximately 54.1% of the Partnership's common and subordinated units, or 94,151,707 common units and 139,704,916 subordinated units, and OGE Energy held approximately 25.7% of the Partnership's common and subordinated units, or 42,832,291 common units and 68,150,514 subordinated units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 4 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 (Enable GP) on an annual or continuing basis and may not remove Enable GP 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, 2017, the Partnership owned a 50% interest in SESH. See Note 6 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.

These condensed consolidated financial statements and the related financial statement disclosures 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 14.

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

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statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Restricted Cash

Restricted cash consists of cash which is restricted by agreements with third parties. The Condensed Consolidated Balance Sheets have $14 million and $17 million of restricted cash as of June 30, 2017 and December 31, 2016, respectively.

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 $4 million and $3 million allowance for doubtful accounts was required as of June 30, 2017 and December 31, 2016, respectively.

(2) New Accounting Pronouncements

Accounting Standards to be Adopted in Future Periods

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in "Revenue Recognition (Topic 605)." Topic 606 is based on the core principle that revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Topic 606 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract.

Topic 606 is effective for fiscal years beginning after December 15, 2017, and interim periods within those years, with early adoption permitted in 2017. However, we do not plan to adopt the standard early. Entities will have the option to apply the standard using a full retrospective or modified retrospective adoption method. The Partnership expects to adopt this ASU using the modified retrospective method. Our evaluation of the impact on our Consolidated Financial Statements and related disclosures is ongoing and not complete. In connection with our assessment work, we formed an implementation work team, completed training on the Topic 606 revenue recognition model and are continuing our review of contracts relative to the provisions of Topic 606.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 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. The Partnership expects to adopt this standard by the first quarter of 2019 and is currently evaluating the impact of this standard on our Condensed Consolidated Financial Statements and related disclosures. In connection with our assessment work, we formed an implementation work team and are continuing our review of our contracts relative to the provisions of the lease standard.

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

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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.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, “Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory.” This standard requires entities to recognize the tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted as of the beginning of an annual period (i.e., only in the first interim period). The guidance requires application using a modified retrospective approach. The Partnership does not expect the adoption of this standard to have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

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(3) 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,	
	2017	2016	2017	2016
	(In millions, except per unit data)			
Net income	$96	$39	$216	$125
Net income attributable to noncontrolling interest	1	—	1	—
Series A Preferred Unit distribution	9	4	18	4
General partner interest in net income	—	—	—	—
Net income available to common and subordinated unitholders	$86	$35	$197	$121
Net income allocable to common units	$45	$18	$102	$61
Net income allocable to subordinated units	41	17	95	60
Net income available to common and subordinated unitholders	$86	$35	$197	$121
Net income allocable to common units	$45	$18	$102	$61
Dilutive effect of Series A Preferred Unit distributions	—	—	—	4
Diluted net income allocable to common units	45	18	102	65
Diluted net income allocable to subordinated units	41	17	95	60
Total	$86	$35	$197	$125
Basic weighted average number of outstanding				
Common units[1]	225	214	225	214
Subordinated units	208	208	208	208
Total	433	422	433	422
Basic earnings per unit				
Common units	$0.20	$0.08	$0.45	$0.29
Subordinated units	$0.20	$0.08	$0.46	$0.29
Basic weighted average number of outstanding common units	225	214	225	214
Dilutive effect of Series A Preferred Units	—	—	—	20
Dilutive effect of performance units	1	1	1	—
Diluted weighted average number of outstanding common units	226	215	226	234
Diluted weighted average number of outstanding subordinated units	208	208	208	208
Total	434	423	434	442
Diluted earnings per unit				
Common units	$0.20	$0.08	$0.45	$0.28
Subordinated units	$0.20	$0.08	$0.46	$0.29

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

The dilutive effect of the unit-based awards discussed in Note 13 was less than $0.01 per unit during each of the three and six months ended June 30, 2017 and 2016.

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(4) 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 during 2016 and 2017 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
June 30, 2017[(1)]	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
September 30, 2016	November 14, 2016	November 22, 2016	$ 0.318	$ 134
June 30, 2016	August 16, 2016	August 23, 2016	$ 0.318	$ 134
March 31, 2016	May 6, 2016	May 13, 2016	$ 0.318	$ 134
December 31, 2015	February 2, 2016	February 12, 2016	$ 0.318	$ 134

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on July 31, 2017, to be paid on August 29, 2017, to common and subordinated unitholders of record at the close of business on August 22, 2017.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2016 and 2017 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
June 30, 2017[(1)]	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
September 30, 2016	November 1, 2016	November 14, 2016	$ 0.625	$ 9
June 30, 2016	August 2, 2016	August 12, 2016	$ 0.625	$ 9
March 31, 2016 [(2)]	May 6, 2016	May 13, 2016	$ 0.2917	$ 4

(1) The board of directors of Enable GP declared a $0.625 per Series A Preferred Unit cash distribution on July 31, 2017, to be paid on August 14, 2017, to Series A Preferred unitholders of record at the close of business on July 31, 2017.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

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 or subordinated units that they own.

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Subordinated Units

General

As of June 30, 2017, all subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because for a period of time, defined by the Partnership Agreement as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received distributions of available cash each quarter from operating surplus in an amount equal to the minimum quarterly distribution, plus any arrearages on minimum quarterly distributions on the common units from prior quarters. In addition, the subordinated units are not entitled to arrearages on minimum quarterly distributions. On the expiration of the subordination period, the subordinated units will convert to common units on a one-for-one basis.

Subordination Period

The subordination period began on the closing date of the IPO and expires on the first to occur of the following dates: (1) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2017 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal or exceed $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date; (b) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum $1.15 (the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during those periods on a fully diluted weighted average basis; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units or (2) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2015 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150% of the annualized minimum quarterly distribution) for the four consecutive quarter period immediately preceding that date; (b) the adjusted operating surplus generated during the four consecutive quarter period immediately preceding that date equaled or exceed $1.725 per unit (150% of the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during that period on a fully diluted weighted average basis plus the corresponding incentive distribution rights; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units.

Expiration of Subordination Period

The Partnership expects that the financial tests required for conversion of all subordinated units will have been met, the subordination period will end and all subordinated units will convert into common units on the first business day following the payment of the cash distribution for common and subordinated units for the second quarter of 2017. Accordingly, the 207,855,430 outstanding subordinated units will convert into common units on a one-for-one basis on August 30, 2017. At conversion, holders of common units resulting from the conversion of subordinated units will have all the rights and obligations of unitholders holding all other common units, including the right to receive pro rata distributions made with respect to common units. The conversion of the subordinated units will not change the aggregate amount of outstanding units, and the Partnership does not anticipate that the conversion of the subordinated units will impact the amount of cash available for distribution by the Partnership.

Series A Preferred Units

On February 18, 2016, the Partnership completed the 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.

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Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to 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.

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement in connection with an at-the-market program (the “ATM Program”). Pursuant to the ATM Program, 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. For the three and six months ended June 30, 2017, the Partnership sold an aggregate of 18,500 common units under the ATM Program, which generated proceeds of approximately $303,000 (net of approximately $3,000 of commissions). The Partnership incurred approximately $345,000 of expenses associated with the filing of the registration statements for the ATM Program. The proceeds were used for general partnership purposes.

2016 Equity Issuance

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting discounts, structuring fees and offering expenses) of $137 million from the offering.

(5) Assessing Impairment of Long-lived Assets (including Intangible Assets)

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. The Partnership recorded no impairments to long-lived assets in the three and six months ended June 30, 2017 or 2016. Based upon review of forecasted undiscounted cash flows, none

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of the asset groups were at risk of failing step one of the impairment test. Commodity price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions could reduce forecast undiscounted cash flows.

(6) 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 and $5 million during the three months ended June 30, 2017 and 2016, respectively, and $11 million and $9 million during the six months ended June 30, 2017 and 2016, respectively, associated with these service agreements.

Equity in Earnings of Equity Method Affiliate:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
SESH	$7	$ 7	$14	$ 14

Distributions from Equity Method Affiliate:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
SESH [1]	$8	$ 7	$19	$ 27

(1) Distributions from equity method affiliate includes a $7 million and $7 million return on investment and a $1 million and zero return of investment for the three months ended June 30, 2017 and 2016, respectively. Distributions from equity method affiliate includes a $14 million and $14 million return on investment and a $5 million and $13 million return of investment for the six months ended June 30, 2017 and 2016, respectively.

Summarized financial information of SESH:

	Three Months Ended	Six Months Ended

	June 30,		June 30,	
	2017	2016	2017	2016
	(In millions)			
Income Statements:				
Revenues	$28	$ 28	$56	$ 57
Operating income	$18	$ 18	$35	$ 37
Net income	$13	$ 14	$26	$ 28

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(7) Debt

The following table presents the Partnership’s outstanding debt as of June 30, 2017 and December 31, 2016.

	June 30, 2017			December 31, 2016		
	Outstanding Principal	Premium (Discount)	Total Debt	Outstanding Principal	Premium (Discount)	Total Debt
	(In millions)					
Revolving Credit Facility	$—	$ —	$—	$636	$ —	$636
2015 Term Loan Agreement	450	—	450	450	—	450
2019 Notes	500	—	500	500	—	500
2024 Notes	600	—	600	600	(1)	599
2027 Notes	700	(3)	697	—	—	—
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	15	265	250	18	268
Total debt	$3,050	$ 12	$3,062	$2,986	$ 17	$3,003
Less: Unamortized debt expense [(1)]			16			10
Total long-term debt			$3,046			$2,993

(1) As of June 30, 2017 and December 31, 2016, there was an additional $4 million and $5 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 June 18, 2015, the Partnership entered into the $1.75 billion Revolving Credit Facility, which matures on June 18, 2020, subject to an extension option, which may 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, 2017, there were no principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility.

The Revolving Credit Facility provides that outstanding borrowings bear interest at 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, 2017, 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, 2017, the commitment fee under the 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 was no amount outstanding under our commercial paper program at each of June 30, 2017 and December 31, 2016. On February 2, 2016, Standard & Poor’s Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial paper program upon maturity and did not issue any additional commercial paper.

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 (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by the Partnership on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of June 30, 2017, there was $450 million outstanding under the 2015 Term Loan Agreement.

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The 2015 Term Loan Agreement provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of June 30, 2017, the applicable margin for LIBOR-based borrowings under the 2015 Term Loan Agreement was 1.375% based on the Partnership's credit ratings. As of June 30, 2017, the weighted average interest rate of the 2015 Term Loan Agreement was 2.27%.

Senior Notes

On March 9, 2017, the Partnership completed the public offering of $700 million 4.400% Senior Notes due 2027 (2027 Notes). The Partnership received net proceeds of approximately $691 million. The proceeds were used for general partnership purposes, including to repay amounts outstanding under the Revolving Credit Facility. The 2027 Notes had an unamortized discount of $3 million and unamortized debt expense of $6 million at June 30, 2017, resulting in an effective interest rate of 4.58% during the six months ended June 30, 2017.

In addition to the 2027 Notes, as of June 30, 2017, the Partnership's debt included the 2019 Notes, 2024 Notes and 2044 Notes, which had $10 million of unamortized debt expense at June 30, 2017, resulting in effective interest rates of 2.58%, 4.02% and 5.08%, respectively, during the six months ended June 30, 2017.

As of June 30, 2017, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes had $15 million of unamortized premium at June 30, 2017, resulting in an effective interest rate of 3.83%, during the six months ended June 30, 2017. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

As of June 30, 2017, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(8) 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, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

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As of June 30, 2017 and December 31, 2016, 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, 2017 and December 31, 2016, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	June 30, 2017		December 31, 2016	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas — TBtu[1]				
Financial fixed futures/swaps	17	21	2	29
Financial basis futures/swaps	17	25	2	30
Physical purchases/sales	2	50	1	25
Crude oil (for condensate) — MBbl[2]				
Financial Futures/swaps	—	330	—	540
Natural gas liquids — MBbl[3]				
Financial Futures/swaps	—	1,310	60	1,133

(1) As of June 30, 2017, 67.0% of the natural gas contracts had durations of one year or less, 14.2% had durations of more than one year and less than two years and 18.8% had durations of more than two years. As of December 31, 2016, 100.0% of the natural gas contracts had durations of one year or less.

(2) As of June 30, 2017 and December 31, 2016, 100% of the crude oil (for condensate) contracts had durations of one year or less.

(3) As of June 30, 2017, 61.1% of the natural gas liquids contracts had durations of one year or less and 38.9% had durations of more than one year and less than two years. As of December 31, 2016, 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, 2017 and December 31, 2016 that were not designated as hedging instruments for accounting purposes are as follows:

		June 30, 2017		December 31, 2016	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current/Other	$4	$ 3	$ 2	$ 22
Physical purchases/sales	Other Current/Other	2	—	—	1
Crude oil (for condensate)					
Financial futures/swaps	Other Current/Other	2	—	—	3
Natural gas liquids					
Financial Futures/swaps	Other Current/Other	—	2	—	8
Total gross derivatives [1]		$8	$ 5	$ 2	$ 34

(1) See Note 9 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Condensed Consolidated Balance Sheets as of June 30, 2017 and December 31, 2016.

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, 2017 and 2016:

	Amounts Recognized in Income			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Natural gas				
Financial futures/swaps gains (losses)	$ 5	$ (21)	$ 16	$ (11)
Physical purchases/sales gains (losses)	2	(4)	7	(8)
Crude oil (for condensate)				
Financial futures/swaps gains (losses)	2	(4)	5	(3)
Natural gas liquids				
Financial futures/swaps gains (losses)	—	(5)	2	(9)
Total	$ 9	$ (34)	$ 30	$ (31)

For derivatives not designated as hedges in the tables above, amounts recognized in income for the periods ended June 30, 2017 and 2016, 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, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Change in fair value of derivatives	$11	$(39)	$35	$(47)
Realized gain (loss) on derivatives	(2)	5	(5)	16
Gain (loss) on derivative activity	$9	$(34)	$30	$(31)

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Credit-Risk Related Contingent Features in Derivative Instruments

Based upon the Partnership's senior unsecured debt rating with Moody's Investors Services or Standard & Poor's Ratings Services, the Partnership could be required to provide 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, 2017, under these obligations, no cash collateral has been posted and no additional collateral may be required to be posted by the Partnership.

(9) 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, 2017, 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, 2017 and December 31, 2016.

	June 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Revolving Credit Facility (Level 2)	$ —	$ —	$ 636	$ 636
2015 Term Loan Agreement (Level 2)	450	450	450	450
2019 Notes (Level 2)	500	496	500	490
2024 Notes (Level 2)	600	595	599	564
2027 Notes (Level 2)	697	705	—	—
2044 Notes (Level 2)	550	521	550	467
EOIT Senior Notes (Level 2)	265	264	268	260

The fair value of the Partnership’s Revolving Credit Facility, 2015 Term Loan Agreement, EOIT Senior Notes, 2019 Notes, 2024 Notes, 2027 Notes and 2044 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, 2017, 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, 2017 and December 31, 2016:

June 30, 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)	$ 4	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	4	—	22	7
Unobservable inputs (Level 3)	—	2	—	—

Total fair value	8	5	22	7
Netting adjustments	(4)	(4)	—	—
Total	$4	$ 1	$ 22	$ 7

December 31, 2016	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	$ 22	$ —	$ —
Significant other observable inputs (Level 2)	—	4	41	30
Unobservable inputs (Level 3)	—	8	—	—
Total fair value	2	34	41	30
Netting adjustments	—	—	—	—
Total	$2	$ 34	$ 41	$ 30

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(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, 2017 and December 31, 2016.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $1 million and zero at June 30, 2017 and December 31, 2016, 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 $2 million and $5 million at June 30, 2017 and December 31, 2016, 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 as of December 31, 2016	$ (8)
Gains included in earnings	2
Settlements	4
Balance as of June 30, 2017	$ (2)

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, 2017
Product Group	Forward Curve Range

	Fair Value (In millions)	(Per gallon)
Natural gas liquids	$(2)	$0.264 - $0.757

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(10) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Six Months Ended June 30, 2017	2016
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 50	$ 51
Income taxes, net of refunds	—	1
Non-cash transactions:		
Accounts payable related to capital expenditures	24	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 Statement of Cash Flows:

	Six Months Ended June 30, 2017	2016
	(In millions)	
Cash and cash equivalents	$ 7	$ 6
Restricted cash	14	—
Cash, cash equivalents and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 21	$ 6

(11) 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: (1) firm transportation with seasonal contract demand, (2) firm storage, (3) no notice transportation with associated storage and (4) maximum rate firm transportation. The first three services are in effect through March 31, 2021, and will remain in effect from year to year thereafter unless either party provides 180 days’ written notice prior to the contract termination date. The maximum rate firm transportation is in effect through March 31, 2018. MRT provides firm transportation and firm storage services to CenterPoint Energy’s LDCs under agreements that are in effect through May 15, 2018, but will continue year to year thereafter unless either party provides twelve months’ written notice prior to the contract termination date.

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 serve OGE Energy’s Muskogee Power Plant.

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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 5% and 7% of total revenues during the three months ended June 30, 2017 and 2016, respectively, and 6% and 8% of total revenues during the six months ended June 30, 2017 and 2016, 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,	
	2017	2016	2017	2016
	(In millions)			
Gas transportation and storage service revenue — CenterPoint Energy	$ 24	$ 24	$ 57	$ 57
Natural gas product sales — CenterPoint Energy	1	—	1	1
Gas transportation and storage service revenue — OGE Energy	9	9	18	18
Natural gas product sales — OGE Energy	—	5	—	6
Total revenues — affiliated companies	$ 34	$ 38	$ 76	$ 82

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,	
	2017	2016	2017	2016
	(In millions)			
Cost of natural gas purchases — CenterPoint Energy	$ 1	$ —	$ 1	$ —
Cost of natural gas purchases — OGE Energy	4	3	7	5
Total cost of natural gas purchases — affiliated companies	$ 5	$ 3	$ 8	$ 5

Corporate services and seconded employee expense

As of June 30, 2017, 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 employee costs arising out of OGE Energy’s defined benefit and retiree medical plans is fixed at $5 million in 2017 and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

Under the terms of the MFA, the Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term that ended on April 30, 2016. The service 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 these service 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 2017 are $3 million and $4 million, respectively.

On November 1, 2016, the Partnership entered into a new lease with an affiliate of CenterPoint Energy pursuant to which the Partnership leases office space in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and extends through December 31, 2019. The Partnership expects to incur approximately $3 million in rent and maintenance expenses through the end of the initial term of the lease. Prior to October 1, 2016, CenterPoint Energy provided the office space in Shreveport, Louisiana, under the services agreement. As of June 30, 2017, CenterPoint Energy continues to provide office and data center space to the Partnership in Houston, Texas, under the services agreement.

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Amounts charged to the Partnership by affiliates for seconded employees 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,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Corporate Services — CenterPoint Energy	$1	$ 3	$2	$ 5
Seconded Employee Costs — OGE Energy	9	8	16	17
Corporate Services — OGE Energy	1	1	2	3
Total corporate services and seconded employees expense	$11	$ 12	$20	$ 25

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement, with 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 4 for further discussion of the Series A Preferred Units.

Notes payable

On February 18, 2016, in connection with the private placement of the Series A Preferred Units, the Partnership redeemed $363 million of notes payable—affiliated companies payable to a subsidiary of CenterPoint Energy. As of June 30, 2017, the Partnership has not had any notes payable to any affiliate and has not incurred interest expense to any affiliate since February 18, 2016.

(12) 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.

(13) Equity-Based Compensation

The following table summarizes the Partnership’s compensation expense for the three and six months ended June 30, 2017 and 2016 related to performance units, restricted units, and phantom units for the Partnership’s employees and independent directors:

	Three Months Ended	Six Months Ended

	June 30,		June 30,	
	2017	2016	2017	2016
	(In millions)			
Performance units	$2	$ 2	$ 5	$ 3
Restricted units	1	1	1	1
Phantom units	1	—	2	1
Total compensation expense	$4	$ 3	$ 8	$ 5

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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, 2017 and changes during 2017 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, 2016	1,969,107	$ 15.27	392,995	$ 20.74	643,604	$ 8.49
Granted[1]	468,626	10.27	—	—	377,979	16.26
Vested[2]	(334,682)	22.61	(148,735)	25.50	(1,869)	8.12
Forfeited	(42,150)	14.93	(7,038)	19.60	(12,420)	10.28
Units Outstanding at June 30, 2017	2,060,901	$ 13.86	237,222	$ 17.80	1,007,294	$ 11.38
Aggregate Intrinsic Value of Units Outstanding at June 30, 2017	$ 33		$ 4		$ 16	

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(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 0 percent to 200 percent of the target.

(2) Performance units vested as of June 30, 2017 include 334,682 units from the annual grant, which were approved by the Board of Directors in 2014 and paid out at 91.5%, or 306,170 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, 2017	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 18	1.79
Restricted Units	1	0.93
Phantom Units	8	2.06
Total	$ 27	

As of June 30, 2017, there were 8,653,478 units available for issuance under the long term incentive plan.

(14) 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 2016 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, 2017	Gathering and Processing	Transportation and Storage(1)	Eliminations	Total
	(In millions)			
Product sales	$336	$ 134	$ (116)	$354
Service revenue	144	129	(1)	272
Total Revenues	480	263	(117)	626
Cost of natural gas and natural gas liquids	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
Total assets	$8,612	$ 5,516	$ (2,997)	$11,131
Capital expenditures	$39	$ 48	$ —	$87

Three Months Ended June 30, 2016	Gathering and Processing	Transportation and Storage(1)	Eliminations	Total
	(In millions)			
Product sales	$256	$ 92	$ (82)	$266
Service revenue	131	133	(1)	263
Total Revenues	387	225	(83)	529
Cost of natural gas and natural gas liquids	231	106	(83)	254
Operation and maintenance, General and administrative	67	53	—	120
Depreciation and amortization	52	31	—	83
Taxes other than income tax	8	7	—	15
Operating income	$29	$ 28	$ —	$57
Total assets as of December 31, 2016	$7,453	$ 4,963	$ (1,204)	$11,212
Capital expenditures	$79	$ 12	$ —	$91

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Six Months Ended June 30, 2017	Gathering and Processing	Transportation and Storage(1)	Eliminations	Total
	(In millions)			
Product sales	$687	$ 287	$ (234)	$740
Service revenue	284	270	(2)	552
Total Revenues	971	557	(236)	1,292
Cost of natural gas and natural gas liquids	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
Total assets	$8,612	$ 5,516	$ (2,997)	$11,131
Capital expenditures	$90	$ 58	$ —	$148

Six Months Ended June 30, 2016	Gathering and Processing	Transportation and Storage(1)	Eliminations	Total
	(In millions)			
Product sales	$464	$ 198	$ (151)	$511
Service revenue	256	273	(2)	527
Total Revenues	720	471	(153)	1,038
Cost of natural gas and natural gas liquids	396	205	(152)	449
Operation and maintenance, General and administrative	142	94	(1)	235
Depreciation and amortization	101	63	—	164
Taxes other than income tax	16	14	—	30
Operating income	$65	$ 95	$ —	$160
Total assets as of December 31, 2016	$7,453	$ 4,963	$ (1,204)	$11,212
Capital expenditures	$200	$ 21	$ —	$221

(1) See Note 6 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, 2017 and 2016.

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, 2016, 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 IPO 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 to 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, a pipeline extending from Louisiana to Alabama.

We expect our business to continue to be affected by the key trends included in our Annual Report. 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 and growing through accretive acquisitions and disciplined development. As part of these efforts, we continuously engage in discussions with new and existing customers regarding the development of 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.

Typically, we do not announce a transaction until after we have executed a definitive agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that the pace of discussions and negotiations regarding potential transactions is unpredictable and can advance or terminate in a short period of time.

Recent Developments

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement in connection with an at-the-market program (the “ATM Program”). Pursuant to the ATM Program, 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. For the three and six months ended June 30, 2017, the Partnership sold an aggregate of 18,500 common units under the ATM Program, which generated proceeds of approximately $303,000 (net of approximately $3,000 of commissions). The Partnership incurred approximately $345,000 of expenses associated with the filing of the registration statements for the ATM Program. The proceeds were used for general partnership purposes.

Issuance of Senior Notes

On March 9, 2017, the Partnership completed the public offering of $700 million 4.400% Senior Notes due 2027 (2027 Notes). The Partnership received net proceeds of approximately $691 million. The proceeds were used for general partnership purposes, including to repay amounts outstanding under the Revolving Credit Facility.

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Commercial and Construction Update

Project Wildcat rich gas takeaway solution

The Partnership has entered into an agreement to deliver approximately 400 MMcf/d of rich natural gas from the Anadarko Basin to north Texas, providing a new market outlet for growing Anadarko Basin production. Project Wildcat is expected to provide access to the Texas intrastate natural gas markets, including the Tolar Hub, by contracting with an affiliate of Energy Transfer Partners, LP for 400 MMcf/d of firm processing capacity at the Godley Plant in Johnson County, Texas. The project is expected to be in service by the end of the second quarter of 2018. 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, though likely not before 2018.

EGT Expansion Project

In March 2017, EGT conducted a non-binding open season to solicit commitments for the Cana and STACK Expansion (CaSE) project, a system expansion providing firm transportation service for growing Anadarko Basin production. The project’s foundation shipper, Newfield Exploration Company, has entered into a 205,000 Dth/d firm natural gas transportation agreement with EGT. The 10-year contract is expected to start at an initial capacity of 45,000 Dth/d in early 2018 and grow to the full contracted capacity by the fourth quarter of 2018.

CenterPoint Strategic Review

In connection with an on-going process to evaluate strategic alternatives for its interest in Enable, CenterPoint Energy has disclosed that it provided notice to OGE Energy of CenterPoint Energy’s solicitation of offers from unrelated third parties to acquire all or a portion of the common units and subordinated units of Enable owned by CenterPoint Energy Resources Corp. (CERC) and all of the membership interests of Enable GP owned by CERC. CenterPoint Energy has also disclosed that it is continuing to evaluate this and other strategic alternatives for its investment in Enable, including evaluating a spin-off, sale or other disposition of CenterPoint Energy’s interests in Enable, and that if none of these options are viable, it intends to reduce its investment in us through the sale of units in the public equity markets, subject to market conditions.

Other Events

Sean Trauschke, President, Chief Executive Officer and Chairman of OGE Energy, and a member of our Board of Directors since May 2013, was appointed to serve as chairman of our Board of Directors on May 29, 2017. Mr. Trauschke’s term as Chairman will expire on May 29, 2019, at which time CenterPoint Energy will have the right to appoint the next chairman. Under the limited liability company agreement of our General Partner, the right to appoint the chairman of the Board of Directors rotates between CenterPoint Energy and OGE Energy every two years.

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Results of Operations

The following tables summarize the key components of our results of operations for the three and six months ended June 30, 2017 and 2016.

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 revenue	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

Three Months Ended June 30, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$256	$ 92	$ (82)	$ 266
Service revenue	131	133	(1)	263
Total Revenues	387	225	(83)	529
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	231	106	(83)	254
Gross margin (1)	156	119	—	275
Operation and maintenance, General and administrative	67	53	—	120
Depreciation and amortization	52	31	—	83
Taxes other than income tax	8	7	—	15
Operating income	$29	$ 28	$ —	$ 57
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

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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 revenue	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

Six Months Ended June 30, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$464	$ 198	$ (151)	$ 511
Service revenue	256	273	(2)	527
Total Revenues	720	471	(153)	1,038
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	396	205	(152)	449
Gross margin [(1)]	324	266	(1)	589
Operation and maintenance, General and administrative	142	94	(1)	235
Depreciation and amortization	101	63	—	164
Taxes other than income tax	16	14	—	30
Operating income	$65	$ 95	$ —	$ 160
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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Operating Data:				
Gathered volumes—TBtu	301	282	597	560
Gathered volumes—TBtu/d	3.31	3.10	3.30	3.07
Natural gas processed volumes—TBtu	174	161	342	323
Natural gas processed volumes—TBtu/d	1.91	1.76	1.89	1.78
NGLs produced—MBbl/d [(1)]	87.12	83.09	83.46	78.36
NGLs sold—MBbl/d [(1)(2)]	86.51	83.80	82.61	80.15
Condensate sold—MBbl/d	5.04	6.08	5.26	6.26
Crude Oil—Gathered volumes—MBbl/d	23.20	25.52	22.19	27.18

Transported volumes—TBtu	445	446	938	911
Transported volumes—TBtu/d	4.86	4.87	5.17	4.99
Interstate firm contracted capacity—Bcf/d	6.21	6.95	6.72	7.06
Intrastate average deliveries—TBtu/d	1.84	1.72	1.84	1.70

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(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,	
	2017	2016	2017	2016
Anadarko				
Gathered volumes—TBtu/d	1.78	1.62	1.77	1.62
Natural gas processed volumes—TBtu/d	1.58	1.44	1.56	1.43
NGLs produced—MBbl/d (1)	74.14	69.64	70.74	64.17
Arkoma				
Gathered volumes—TBtu/d	0.54	0.65	0.55	0.63
Natural gas processed volumes—TBtu/d	0.09	0.10	0.09	0.10
NGLs produced—MBbl/d (1)	4.60	5.03	4.72	5.01
Ark-La-Tex				
Gathered volumes—TBtu/d	0.99	0.83	0.98	0.82
Natural gas processed volumes—TBtu/d	0.24	0.22	0.24	0.25
NGLs produced—MBbl/d (1)	8.38	8.42	8.00	9.18

(1) Excludes condensate.

Gathering and Processing

Three Months Ended June 30, 2017 compared to three months ended June 30, 2016. Our gathering and processing segment reported operating income of $72 million for the three months ended June 30, 2017 compared to operating income of $29 million for the three months ended June 30, 2016. The difference of $43 million in operating income between periods was primarily due to a $55 million increase in gross margin. This was partially offset by an $8 million increase in operation and maintenance and general and administrative expenses, a $3 million increase in depreciation and amortization and a $1 million increase in taxes other than income tax during the three months ended June 30, 2017.

Our gathering and processing segment revenues increased $93 million. The increase was primarily due to a $33 million increase in revenues from NGL sales resulting from higher average NGL prices, a $31 million increase in revenues from sales of natural gas as a result of higher average natural gas prices, a $15 million increase in revenues from changes to the fair value of condensate and NGL derivatives, a $7 million increase in processing service revenues resulting from higher processed volumes primarily due to a percent-of-proceeds contract that was converted to a fee-based contract during the second half of 2016, a $6 million increase in natural gas gathering revenues due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins and a $1 million increase in revenues due to increased water transportation services in the Williston Basin. These increases were partially offset by a $2 million decrease in revenues due to a wind-down of third-party measurement and communication services in 2017.

Our gathering and processing segment gross margin increased $55 million. The increase was primarily due to a $25 million increase in natural gas sales due to higher average natural gas prices and higher volumes in the Anadarko and Ark-La-Tex Basins, a $15 million increase in gross margin from changes in the fair value of condensate and NGL derivatives, a $7 million increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $6 million increase in gathering margin due to increased gathered volumes in the Anadarko and Ark-La-Tex Basins, a $3 million increase in margin associated with our annual fuel rate determination and a $1 million increase due to increased water transportation services in the Williston Basin. These increases were partially offset by a $2 million decrease in margin due to a wind-down of third-party measurement and communication services in 2017.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $8 million. The increase was primarily due to a $3 million increase in payroll-related costs, a $2 million increase in operating expenses associated with additional assets placed in service, a $2 million increase in various other operating costs and a $1 million increase from the collection of a previously reserved allowance for doubtful accounts in 2016, with no comparable item in 2017.

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Our gathering and processing segment depreciation and amortization increased $3 million due to additional assets placed in service.

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, 2017 compared to six months ended June 30, 2016. Our gathering and processing segment reported operating income of $142 million for the six months ended June 30, 2017 compared to operating income of $65 million for the six months ended June 30, 2016. The difference of $77 million in operating income between periods was primarily due to a $92 million increase in gross margin. This was partially offset by a $10 million increase in depreciation and amortization, a $3 million increase in operation and maintenance and general and administrative expenses and a $2 million increase in taxes other than income tax during the six months ended June 30, 2017.

Our gathering and processing segment revenues increased $251 million. The increase was primarily due to a $119 million increase in revenues from NGL sales resulting from higher average NGL prices, a $74 million increase in revenues from sales of natural gas as a result of higher average natural gas prices, a $31 million increase in revenues from changes to the fair value of condensate and NGL derivatives, a $14 million increase in processing service revenues resulting from higher processed volumes primarily due to a percent-of-proceeds contract that was converted to a fee-based contract in the second half of 2016, a $12 million increase in natural gas gathering revenues due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins and a $2 million increase in revenues due to increased water transportation services in the Williston Basin. These increases were partially offset by a $2 million decrease in revenues due to a wind-down of third-party measurement and communication services in 2017.

Our gathering and processing segment gross margin increased $92 million. The increase was primarily due to a $36 million increase in natural gas sales due to higher average natural gas prices and higher volumes in the Anadarko and Ark-La-Tex Basins, a $31 million increase in gross margin from changes in the fair value of condensate and NGL derivatives, an $18 million increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $12 million increase in gathering margin due to increased gathered volumes in the Anadarko and Ark-La-Tex Basins and a $2 million increase due to increased water transportation services in the Williston Basin. These increases were partially offset by a $6 million decrease in margin associated with our annual fuel rate determination and a $2 million decrease in margin due to a wind-down of third-party measurement and communication services in 2017.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $3 million. The increase was primarily due to a $4 million increase in payroll-related costs and a $2 million increase in operating expenses associated with additional assets placed in service. These increases were partially offset by a $1 million reduction in equipment rentals, a $1 million reduction in information technology-related costs and a $1 million decrease in allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization increased $10 million due to additional assets placed in service.

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.

Transportation and Storage

Three Months Ended June 30, 2017 compared to three months ended June 30, 2016. Our transportation and storage segment reported operating income of $50 million for the three months ended June 30, 2017 compared to operating income of $28 million for the three months ended June 30, 2016. The difference of $22 million in operating income between periods was primarily due to a $17 million increase in gross margin and an $8 million decrease in operation and maintenance and general and administrative expenses, partially offset by a $3 million increase in depreciation and amortization for the three months ended June 30, 2017.

Our transportation and storage segment revenues increased $38 million. The increase was primarily due to a $36 million increase in revenues from changes in the fair value of natural gas derivatives, a $9 million increase in revenues from natural gas sales associated with higher sales volumes and higher average sales prices, a $3 million increase in revenues from off-system transportation, a $2 million increase in revenues from firm transportation and a $2 million increase in revenues from NGL sales due to an increase in prices. These increases were partially offset by a decrease of $5 million due to realized losses on natural gas derivatives as compared to realized gains in 2016, a $5 million decrease in firm transportation services between Carthage, Texas, and Perryville, Louisiana, and a $1 million decrease in revenues on transportation services for LDCs.

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Our transportation and storage segment gross margin increased $17 million. The increase was primarily due to a $36 million increase in gross margin from changes in the fair value of natural gas derivatives, a $1 million increase in off-system transportation margins and a $1 million increase in NGL sales due to an increase in prices. These increases were partially offset by an $11 million decrease in system management activities, a decrease of $5 million due to realized losses on natural gas derivatives as compared to realized gains in 2016 and a $5 million decrease in firm transportation services between Carthage, Texas and Perryville, Louisiana.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $8 million. The decrease was primarily due to a $5 million decrease in materials and supplies and contract services, a $2 million decrease in loss on sale of assets and $1 million decrease in information technology-related costs.

Our transportation and storage segment depreciation and amortization increased $3 million due to additional assets placed in service.

Six months ended June 30, 2017 compared to six months ended June 30, 2016. Our transportation and storage segment reported operating income of $120 million in the six months ended June 30, 2017 compared to operating income of $95 million in the six months ended June 30, 2016. The difference of $25 million in operating income between periods was primarily due to a $24 million increase in gross margin and a $4 million decrease in operation and maintenance and general and administrative expenses, partially offset by a $3 million increase in depreciation and amortization for the six months ended June 30, 2017.

Our transportation and storage segment revenues increased $86 million. The increase was primarily due to a $52 million increase in revenues from changes in the fair value of natural gas derivatives, a $42 million increase in revenues from higher natural gas sales associated with higher sales volumes and higher average sales prices, a $5 million increase in revenues from NGL sales due to an increase in prices, a $3 million increase in revenues from off-system transportation and a $2 million increase in revenues from firm transportation. These increases were partially offset by a decrease of $10 million due to lower realized gains on natural gas derivatives, a $4 million decrease in firm transportation services between Carthage, Texas, and Perryville, Louisiana, and a $1 million decrease in revenues on transportation services for LDCs.

Our transportation and storage segment gross margin increased $24 million. The increase was primarily due to a $52 million increase in gross margin from changes in the fair value of natural gas derivatives, a $3 million increase in off-system transportation margins, a $3 million increase in NGL sales due to an increase in prices and a $2 million increase in firm transportation. These increases were partially offset by a $21 million decrease in system management activities, a decrease of $10 million due to lower realized gains on natural gas derivatives, a decrease of $4 million in firm transportation services between Carthage, Texas, and Perryville, Louisiana, and a $1 million decrease in margins on transportation services for LDCs.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $4 million. The decrease was primarily due to a $4 million decrease in materials and supplies and contract services, a $2 million decrease in loss on sale of assets and a $1 million decrease in information technology-related costs. These decreases were partially offset by a $3 million increase in payroll-related costs.

Our transportation and storage segment depreciation and amortization increased $3 million due to additional assets placed in service.

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Condensed Consolidated Interim Information

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Operating Income	$122	$57	$262	$160
Other Income (Expense):				
Interest expense	(31)	(25)	(58)	(48)
Equity in earnings of equity method affiliate	7	7	14	14
Other, net	(1)	—	—	—
Total Other Expense	(25)	(18)	(44)	(34)
Income Before Income Taxes	97	39	218	126
Income tax expense	1	—	2	1
Net Income	$96	$39	$216	$125
Less: Net income attributable to noncontrolling interest	1	—	1	—
Net Income Attributable to Limited Partners	$95	$39	$215	$125
Less: Series A Preferred Unit distributions	9	4	18	4
Net Income Attributable to Common and Subordinated Units	$86	$35	$197	$121

Three Months Ended June 30, 2017 compared to Three Months Ended June 30, 2016

Net Income attributable to limited partners. We reported net income attributable to limited partners of $95 million in the three months ended June 30, 2017 compared to net income attributable to limited partners of $39 million in the three months ended June 30, 2016. The increase in net income attributable to limited partners of $56 million was primarily attributable to an increase in operating income of $65 million, partially offset by an increase in interest expense of $6 million and an increase in other expense of $1 million in the three months ended June 30, 2017.

Interest Expense. Interest expense increased $6 million primarily due to higher interest rates on the Partnership's outstanding debt.

Six Months Ended June 30, 2017 compared to Six Months Ended June 30, 2016

Net Income attributable to limited partners. We reported net income attributable to limited partners of $215 million in the six months ended June 30, 2017 compared to net income attributable to limited partners of $125 million in the six months ended June 30, 2016. The increase in net income attributable to limited partners of $90 million was primarily attributable to an increase in operating income of $102 million, partially offset by an increase in interest expense of $10 million in the six months ended June 30, 2017.

Interest Expense. Interest expense increased $10 million primarily due to higher interest rates on the Partnership's outstanding debt.

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

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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.

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(In millions)			
Reconciliation of Gross margin to Total Revenues:				
Consolidated				
Product sales	$354	$266	$740	$511
Service revenue	272	263	552	527
Total Revenues	626	529	1,292	1,038
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	279	254	587	449
Gross margin	$347	$275	$705	$589
Reportable Segments				
Gathering and Processing				
Product sales	$336	$256	$687	$464
Service revenue	144	131	284	256
Total Revenues	480	387	971	720
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	269	231	555	396
Gross margin	$211	$156	$416	$324
Transportation and Storage				
Product sales	$134	$92	$287	$198
Service revenue	129	133	270	273
Total Revenues	263	225	557	471
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	127	106	267	205
Gross margin	$136	$119	$290	$266

The following table shows the components of our gross margin for the six months ended June 30, 2017:

	Fee-Based Demand/ Commitment/ Guaranteed Return	Volume Dependent	Commodity-Based	Total
Six Months Ended June 30, 2017				
Gathering and Processing Segment	25 %	46 %	29 %	100 %
Transportation and Storage Segment	84 %	5 %	11 %	100 %
Partnership Weighted Average	49 %	29 %	22 %	100 %

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	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
	(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	$39	$215	$125
Depreciation and amortization expense	89	83	177	164
Interest expense, net of interest income	31	25	58	48
Income tax expense	1	—	2	1
Distributions received from equity method affiliate in excess of equity earnings	1	—	5	13
Non-cash equity-based compensation	4	3	8	5
Change in fair value of derivatives	(11)	39	(35)	47
Other non-cash losses[1]	5	7	6	8
Adjusted EBITDA	$215	$196	$436	$411
Series A Preferred Unit distributions[2]	(9)	(9)	(18)	(13)
Distributions for phantom and performance units	(1)	—	(1)	—
Adjusted interest expense[3]	(32)	(26)	(59)	(49)
Maintenance capital expenditures	(17)	(17)	(31)	(30)
Current income taxes	—	—	—	(1)
DCF	$156	$144	$327	$318
Distributions related to common and subordinated unitholders[4]	$138	$134	$275	$268
Distribution coverage ratio	1.13	1.07	1.19	1.18

(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, 2017 and 2016. The six months ended June 30, 2016 amount includes the prorated quarterly cash distribution on the Series A preferred Units declared on April 26, 2016. 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) See below for a reconciliation of Adjusted interest expense to Interest expense.

(4) Represents cash distributions declared for common and subordinated units outstanding as of each respective period. Amounts for 2017 reflect estimated cash distributions for common and subordinated units outstanding for the quarter ended June 30, 2017.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:				
Net cash provided by operating activities	$226	$172	$382	$289
Interest expense, net of interest income	31	25	58	48
Net income attributable to noncontrolling interest	(1)	—	(1)	—
Income tax expense	1	—	2	1
Deferred income tax expense	(1)	—	(2)	—
Other non-cash items[1]	1	1	2	2
Changes in operating working capital which (provided) used cash:				
Accounts receivable	(18)	2	(28)	(22)
Accounts payable	(9)	(3)	46	84
Other, including changes in noncurrent assets and liabilities	(5)	(40)	7	(51)