Enable Midstream Partners, LP
Form 10-Q
November 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 September 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 October 13, 2017, there were 432,566,554 common units outstanding.

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AVAILABLE INFORMATION

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

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

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

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GLOSSARY OF TERMS

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, current income taxes and distributions for phantom and performance units.
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 an approximately 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex Basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates an approximately 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.

EOIT Senior Notes.	$250 million 6.25% senior notes due 2020.
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.

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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.
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 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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions, except per unit data)			
Revenues (including revenues from affiliates (Note 11)):				
Product sales	$396	$326	$1,136	$837
Service revenue	309	294	861	821
Total Revenues	705	620	1,997	1,658
Cost and Expenses (including expenses from affiliates (Note 11)):				
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	349	268	936	717
Operation and maintenance	91	87	277	275
General and administrative	23	21	71	68
Depreciation and amortization	90	84	267	248
Impairments (Note 5)	—	8	—	8
Taxes other than income tax	15	13	47	43
Total Cost and Expenses	568	481	1,598	1,359
Operating Income	137	139	399	299
Other Income (Expense):				
Interest expense (including expenses from affiliates (Note 11))	(31)	(26)	(89)	(74)
Equity in earnings of equity method affiliate	7	8	21	22
Total Other Expense	(24)	(18)	(68)	(52)
Income Before Income Tax	113	121	331	247
Income tax expense	—	2	2	3
Net Income	$113	$119	$329	$244
Less: Net income attributable to noncontrolling interest	—	—	1	—
Net Income Attributable to Limited Partners	$113	$119	$328	$244
Less: Series A Preferred Unit distributions (Note 4)	9	9	27	13
Net Income Attributable to Common and Subordinated Units (Note 3)	$104	$110	$301	$231
Basic earnings per unit (Note 3)				
Common units	$0.24	$0.26	$0.70	$0.55
Subordinated units	$0.24	$0.26	$0.69	$0.55
Diluted earnings per unit (Note 3)				
Common units	$0.24	$0.26	$0.69	$0.55
Subordinated units	$0.24	$0.26	$0.69	$0.55

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

	September 30, 2017	December 31, 2016
	(In millions)	
Current Assets:		
Cash and cash equivalents	$8	$ 6
Restricted cash	14	17
Accounts receivable, net of allowance for doubtful accounts	321	249
Accounts receivable—affiliated companies	13	13
Inventory	40	41
Gas imbalances	16	41
Other current assets	34	29
Total current assets	446	396
Property, Plant and Equipment:		
Property, plant and equipment	11,824	11,567
Less accumulated depreciation and amortization	1,650	1,424
Property, plant and equipment, net	10,174	10,143
Other Assets:		
Intangible assets, net	286	306
Investment in equity method affiliate	320	329
Other	36	38
Total other assets	642	673
Total Assets	$11,262	$ 11,212
Current Liabilities:		
Accounts payable	$198	$ 181
Accounts payable—affiliated companies	3	3
Current portion of long-term debt	450	—
Taxes accrued	54	30
Gas imbalances	18	35
Other	108	113
Total current liabilities	831	362
Other Liabilities:		
Accumulated deferred income taxes, net	12	10
Regulatory liabilities	21	19
Other	38	34
Total other liabilities	71	63
Long-Term Debt	2,669	2,993
Commitments and Contingencies (Note 12)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at September 30, 2017 and December 31, 2016)	362	362
Common units (432,563,899 issued and outstanding at September 30, 2017 and 224,535,454 issued and outstanding at December 31, 2016, respectively)	7,317	3,737
Subordinated units (0 issued and outstanding at September 30, 2017 and 207,855,430 issued and outstanding at December 31, 2016, respectively)	—	3,683
Noncontrolling interest	12	12
Total Partners' Equity	7,691	7,794

Total Liabilities and Partners’ Equity	$11,262	$ 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)

	Nine Months Ended September 30,	
	2017	2016
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$329	$244
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	267	248
Deferred income taxes	2	4
Impairments	—	8
Loss on sale/retirement of assets	7	9
Equity in earnings of equity method affiliate	(21)	(22)
Return on investment in equity method affiliate	21	22
Equity-based compensation	12	9
Amortization of debt costs and discount (premium)	(1)	(2)
Changes in other assets and liabilities:		
Accounts receivable, net	(72)	(33)
Accounts receivable—affiliated companies	—	8
Inventory	1	11
Gas imbalance assets	25	3
Other current assets	(5)	3
Other assets	2	(1)
Accounts payable	(16)	(84)
Accounts payable—affiliated companies	—	(4)
Gas imbalance liabilities	(17)	(3)
Other current liabilities	17	68
Other liabilities	5	10
Net cash provided by operating activities	556	498
Cash Flows from Investing Activities:		
Capital expenditures	(250)	(289)
Proceeds from sale of assets	1	1
Return of investment in equity method affiliate	9	18
Net cash used in investing activities	(240)	(270)
Cash Flows from Financing Activities:		
Proceeds from long term debt, net of issuance costs	691	—
Proceeds from revolving credit facility	591	838
Repayment of revolving credit facility	(1,154)	(393)
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	(443)	(417)
Cash taxes paid for employee equity-based compensation	(2)	—
Net cash used in financing activities	(317)	(209)

Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(1)	19
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	23	4
Cash, Cash Equivalents and Restricted Cash at End of Period	$22	$23

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	—	13	—	117	—	114	—	244
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Distributions	—	(13)	—	(205)	—	(198)	(1)	(417)
Equity-based compensation, net of units for employee taxes	—	—	—	9	—	—	—	9
Balance as of September 30, 2016	15	$362	214	$3,635	208	$3,721	$ 11	$7,729
Balance as of December 31, 2016	15	$362	224	$3,737	208	$3,683	$ 12	$7,794
Net income	—	27	—	167	—	134	1	329
Conversion of subordinated units	—	—	208	3,619	(208)	(3,619)	—	—
Distributions	—	(27)	—	(216)	—	(198)	(1)	(442)
Equity-based compensation, net of units for employee taxes	—	—	1	10	—	—	—	10
Balance as of September 30, 2017	15	$362	433	$7,317	—	$—	$ 12	$7,691

See Notes to the Unaudited Condensed Consolidated Financial Statements
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ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (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 September 30, 2017, CenterPoint Energy held approximately 54.1% or 233,856,623 of the Partnership's common units, and OGE Energy held approximately 25.7% or 110,982,805 of the Partnership's common 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 September 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 statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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Restricted Cash

Restricted cash 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 September 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 $3 million allowance for doubtful accounts was required at each of September 30, 2017 and December 31, 2016.

(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. We continue to evaluate the impact this standard will have on the Partnership, which includes our review of contracts and transaction types across all our business segments. We continue to review the potential impact on certain commodity-based gathering and processing contract types. Due to this ongoing analysis, we cannot yet determine the quantitative impact on revenues or cost of natural gas and natural gas liquids from the adoption of Topic 606, however, we currently believe the adoption will not have a material impact on operating income or net income. Based on our analysis to date, we do not expect material changes in the timing of revenue recognition or our accounting policies. We continue to develop and evaluate our Topic 606 disclosures, as well as changes to internal controls necessary for adoption. The Partnership will adopt the revenue recognition standard in the first quarter of 2018 and expects to adopt Topic 606 using the modified retrospective method.

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 in 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

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record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions, except per unit data)			
Net income	$113	$119	$329	$244
Net income attributable to noncontrolling interest	—	—	1	—
Series A Preferred Unit distribution	9	9	27	13
General partner interest in net income	—	—	—	—
Net income available to common and subordinated unitholders	$104	$110	$301	$231
Net income allocable to common units	$71	$56	$174	$117
Net income allocable to subordinated units	33	54	127	114
Net income available to common and subordinated unitholders	$104	$110	$301	$231
Net income allocable to common units	$71	$56	$174	$117
Dilutive effect of Series A Preferred Unit distributions	—	—	—	—
Diluted net income allocable to common units	71	56	174	117
Diluted net income allocable to subordinated units	33	54	127	114
Total	$104	$110	$301	$231
Basic weighted average number of outstanding				
Common units[1]	298	214	250	214
Subordinated units	136	208	183	208
Total	434	422	433	422
Basic earnings per unit				
Common units	$0.24	$0.26	$0.70	$0.55
Subordinated units	$0.24	$0.26	$0.69	$0.55
Basic weighted average number of outstanding common units	298	214	250	214
Dilutive effect of Series A Preferred Units	—	—	—	—
Dilutive effect of performance units	1	—	1	—
Diluted weighted average number of outstanding common units	299	214	251	214
Diluted weighted average number of outstanding subordinated units	136	208	183	208
Total	435	422	434	422
Diluted earnings per unit				
Common units	$0.24	$0.26	$0.69	$0.55
Subordinated units	$0.24	$0.26	$0.69	$0.55

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

See Note 4 for discussion of the expiration of the subordination period.

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

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

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
September 30, 2017[(1)]	November 14, 2017	November 21, 2017	$ 0.318	$ 138
June 30, 2017	August 22, 2017	August 29, 2017	$ 0.318	$ 138
March 31, 2017	May 23, 2017	May 30, 2017	$ 0.318	$ 137
December 31, 2016	February 21, 2017	February 28, 2017	$ 0.318	$ 137
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 October 31, 2017, to be paid on November 21, 2017, to common unitholders of record at the close of business on November 14, 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
September 30, 2017[(1)]	October 31, 2017	November 14, 2017	$ 0.625	$ 9
June 30, 2017	July 31, 2017	August 14, 2017	$ 0.625	$ 9
March 31, 2017	May 2, 2017	May 12, 2017	$ 0.625	$ 9
December 31, 2016	February 10, 2017	February 15, 2017	$ 0.625	$ 9
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 October 31, 2017, to be paid on November 14, 2017, to Series A Preferred unitholders of record at the close of business on October 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

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quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units that they own.

Expiration of Subordination Period

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

Series A Preferred Units

On February 18, 2016, the Partnership completed 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.

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.

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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 nine months ended September 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. During each of the three and nine months ended September 30, 2016, the Partnership recorded an $8 million impairment to the Service Star business line, which is included in Impairments on the Condensed Consolidated Statements of Income and impaired substantially all of the remaining net book value of the Service Star business line. The Service Star business line was a component of the gathering and processing segment that provided measurement and communication services to third parties and the impairment was primarily driven by the impact of planned technology changes affecting Service Star. The Partnership recorded no impairments to long-lived assets in the three and nine months ended September 30, 2017. Based upon review of forecasted undiscounted cash flows, none 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 $3 million for each of the three months ended September 30, 2017 and 2016, and $14 million and $12 million during the nine months ended September 30, 2017 and 2016, respectively, associated with these service agreements.

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Equity in Earnings of Equity Method Affiliate:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
SESH	$7	$ 8	$ 21	$ 22

Distributions from Equity Method Affiliate:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
SESH [(1)]	$ 11	$ 13	$ 30	$ 40

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(1) Distributions from equity method affiliate includes a $7 million and $8 million return on investment and a $4 million and $5 million return of investment for the three months ended September 30, 2017 and 2016, respectively. Distributions from equity method affiliate includes a $21 million and $22 million return on investment and a $9 million and $18 million return of investment for the nine months ended September 30, 2017 and 2016, respectively.

Summarized financial information of SESH:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Income Statements:				
Revenues	$ 29	$ 29	$ 85	$ 86
Operating income	$ 18	$ 19	$ 53	$ 56
Net income	$ 14	$ 15	$ 40	$ 43

(7) Debt

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

	September 30, 2017			December 31, 2016		
	Outstanding Principal	Premium (Discount)	Total Debt	Outstanding Principal	Premium (Discount)	Total Debt
	(In millions)					
Revolving Credit Facility	$ 73	$ —	$ 73	$ 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	14	264	250	18	268
Total debt	$3,123	$ 11	$3,134	$2,986	$ 17	$3,003
Less: Current portion of long-term debt			450			—
Less: Unamortized debt expense [1]			15			10
Total long-term debt			$2,669			$2,993

(1) As of September 30, 2017 and December 31, 2016, there was an additional $3 million and $5 million, respectively, of unamortized debt expense related to the Revolving Credit Facility included in Other long-term assets, not included above.

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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 September 30, 2017, there were $73 million principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 2.74% as of September 30, 2017.

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 September 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 September 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 September 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 September 30, 2017, there was $450 million outstanding under the 2015 Term Loan Agreement, which is included as Current portion of long-term debt in the Partnership's Condensed Consolidated Balance Sheets.

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 September 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. For the nine months ended September 30, 2017, the weighted average interest rate of the 2015 Term Loan Agreement was 2.38%.

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 September 30, 2017, resulting in an effective interest rate of 4.58% during the nine months ended September 30, 2017.

In addition to the 2027 Notes, as of September 30, 2017, the Partnership’s debt included the 2019 Notes, 2024 Notes and 2044 Notes, which had $9 million of unamortized debt expense at September 30, 2017, resulting in effective interest rates of 2.58%, 4.02% and 5.08%, respectively, during the nine months ended September 30, 2017.

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As of September 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 $14 million of unamortized premium at September 30, 2017, resulting in an effective interest rate of 3.82%, during the nine months ended September 30, 2017.

As of September 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.

As of September 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.

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

	September 30, 2017		December 31, 2016	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas—TBtu[1]				
Financial fixed futures/swaps	17	19	2	29
Financial basis futures/swaps	19	24	2	30
Physical purchases/sales	1	46	1	25
Crude oil (for condensate)—MBbl[2]				
Financial Futures/swaps	—	490	—	540
Natural gas liquids—MBbl[3]				
Financial Futures/swaps	15	1,701	60	1,133

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(1) As of September 30, 2017, 70.8% of the natural gas contracts had durations of one year or less, 13.0% had durations of more than one year and less than two years and 16.2% 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 September 30, 2017, 87.8% of the crude oil (for condensate) contracts had durations of one year or less and 12.2% had durations of more than one year and less than two years. As of December 31, 2016, 100% of the crude oil (for condensate) contracts had durations of one year or less.

(3) As of September 30, 2017, 79.9% of the natural gas liquids contracts had durations of one year or less and 20.1% 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.

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 September 30, 2017 and December 31, 2016 that were not designated as hedging instruments for accounting purposes are as follows:

		September 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	3	—	—	1
Crude oil (for condensate)					

Financial futures/swaps	Other Current/Other	—	1	—	3
Natural gas liquids					
Financial Futures/swaps	Other Current/Other	—	6	—	8
Total gross derivatives [(1)]		$7	$ 10	$ 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 September 30, 2017 and December 31, 2016.

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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 nine months ended September 30, 2017 and 2016:

	Amounts Recognized in Income			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Natural gas				
Financial futures/swaps gains (losses)	$ 1	$ 6	$ 17	$ (5)
Physical purchases/sales gains (losses)	1	1	8	(7)
Crude oil (for condensate)				
Financial futures/swaps gains (losses)	(2)	1	3	(2)
Natural gas liquids				
Financial futures/swaps gains (losses)	(7)	1	(5)	(8)
Total	$ (7)	$ 9	$ 23	$ (22)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Change in fair value of derivatives	$ (6)	$ 8	$ 29	$ (40)
Realized gain (loss) on derivatives	(1)	1	(6)	18
Gain (loss) on derivative activity	$ (7)	$ 9	$ 23	$ (22)

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 September 30, 2017, under these obligations, $1 million of cash collateral has been posted and $1 million of 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 September 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 September 30, 2017 and December 31, 2016.

	September 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2)	$ 73	$ 73	$ 636	$ 636
2015 Term Loan Agreement (Level 2)	450	450	450	450
2019 Notes (Level 2)	500	498	500	490
2024 Notes (Level 2)	600	601	599	564
2027 Notes (Level 2)	697	716	—	—
2044 Notes (Level 2)	550	537	550	467

EOIT Senior Notes (Level 2)	264	266	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 September 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 September 30, 2017 and December 31, 2016:

September 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	$ 2	$ —	$ —
Significant other observable inputs (Level 2)	3	2	14	18
Unobservable inputs (Level 3)	—	6	—	—
Total fair value	7	10	14	18
Netting adjustments	(4)	(4)	—	—
Total	$3	$ 6	$ 14	$ 18

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

(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 September 30, 2017 and December 31, 2016.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $2 million and zero at September 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 zero and $5 million at September 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)
Losses included in earnings	(5)
Settlements	7
Balance as of September 30, 2017	$ (6)

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.

	September 30, 2017	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$(6)	$0.282 - $1.081

(10) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Nine Months Ended September 30,	
	2017	2016
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 77	$ 67
Income taxes, net of refunds	—	1
Non-cash transactions:		
Accounts payable related to capital expenditures	52	32

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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:

	Nine Months Ended September 30,	
	2017	2016
	(In millions)	
Cash and cash equivalents	$ 8	$ 23
Restricted cash	14	—
Cash, cash equivalents and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 22	$ 23

(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, 2023, 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 expand the EOIT system.

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.

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The Partnership's revenues from affiliated companies accounted for 5% and 6% of total revenues during the three months ended September 30, 2017 and 2016, respectively, and 5% and 7% of total revenues during the nine months ended September 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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Gas transportation and storage service revenue — CenterPoint Energy	$ 22	$ 22	$ 79	$ 79
Natural gas product sales — CenterPoint Energy	—	—	1	1
Gas transportation and storage service revenue — OGE Energy	9	10	27	28
Natural gas product sales — OGE Energy	2	4	2	10
Total revenues — affiliated companies	$ 33	$ 36	$ 109	$ 118

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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Cost of natural gas purchases — CenterPoint Energy	$ —	$ —	$ 1	$ —
Cost of natural gas purchases — OGE Energy	6	4	13	9
Total cost of natural gas purchases — affiliated companies	$ 6	$ 4	$ 14	$ 9

Seconded employee, corporate services and operating lease expense

As of September 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, unless and until secondment is terminated.

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 September 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, an operating lease and corporate services, included primarily in Operation and maintenance and General and administrative expenses in the Partnership's Condensed Consolidated Statements of Income are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Corporate Services — CenterPoint Energy	$ —	$ 1	$ 2	$ 6
Operating Lease — CenterPoint Energy	1	—	1	—
Seconded Employee Costs — OGE Energy	7	5	23	22
Corporate Services — OGE Energy	1	1	3	4
Total corporate services and seconded employees expense	$ 9	$ 7	$ 29	$ 32

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 September 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 nine months ended September 30, 2017 and 2016 related to performance units, restricted units, and phantom units for the Partnership's employees and independent directors:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Performance units	$ 3	$ 4	$ 8	$ 7
Restricted units	—	1	1	2
Phantom units	1	—	3	1
Total compensation expense	$ 4	$ 5	$ 12	$ 10

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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 September 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	392,952	$ 20.74	643,604	$ 8.49
Granted[1]	468,626	19.27	—	—	389,209	16.24
Vested[2]	(334,682)	22.61	(149,126)	25.47	(15,937)	13.18
Forfeited	(42,150)	14.93	(8,666)	19.07	(19,799)	11.42
Units Outstanding at September 30, 2017	2,060,901	$ 13.86	235,160	$ 17.81	997,077	$ 11.38
Aggregate Intrinsic Value of Units Outstanding at September 30, 2017	$ 33		$ 4		$ 16	

(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 September 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.

	September 30, 2017	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 15	1.54
Restricted Units	1	0.68
Phantom Units	8	1.83
Total	$ 24	

As of September 30, 2017, there were 8,656,035 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 September 30, 2017	Gathering and Processing	Transportation and Storage[1]	Eliminations	Total
	(In millions)			
Product sales	$357	$ 152	$ (113)	$396
Service revenue	185	125	(1)	309
Total Revenues	542	277	(114)	705
Cost of natural gas and natural gas liquids	308	154	(113)	349
Operation and maintenance, General and administrative	70	45	(1)	114
Depreciation and amortization	56	34	—	90
Taxes other than income tax	9	6	—	15
Operating income	$99	$ 38	$ —	$137
Total assets	$8,749	$ 5,560	$ (3,047)	$11,262
Capital expenditures	$86	$ 16	$ —	$102

Three Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage[1]	Eliminations	Total
	(In millions)			
Product sales	$295	$ 150	$ (119)	$326
Service revenue	160	135	(1)	294
Total Revenues	455	285	(120)	620
Cost of natural gas and natural gas liquids	246	141	(119)	268
Operation and maintenance, General and administrative	63	46	(1)	108
Depreciation and amortization	53	31	—	84
Impairments	8	—	—	8
Taxes other than income tax	8	5	—	13
Operating income	$77	$ 62	$ —	$139
Total assets as of December 31, 2016	$7,453	$ 4,963	$ (1,204)	$11,212
Capital expenditures	$52	$ 16	$ —	$68

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Nine Months Ended September 30, 2017	Gathering and Processing	Transportation and Storage[(1)]	Eliminations	Total
	(In millions)			
Product sales	$1,044	$ 439	$ (347)	$1,136
Service revenue	469	395	(3)	861
Total Revenues	1,513	834	(350)	1,997
Cost of natural gas and natural gas liquids	863	421	(348)	936
Operation and maintenance, General and administrative	215	135	(2)	348
Depreciation and amortization	167	100	—	267
Taxes other than income tax	27	20	—	47
Operating income	$241	$ 158	$ —	$399
Total assets	$8,749	$ 5,560	$ (3,047)	$11,262
Capital expenditures	$176	$ 74	$ —	$250

Nine Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage[(1)]	Eliminations	Total
	(In millions)			
Product sales	$759	$ 348	$ (270)	$837
Service revenue	416	408	(3)	821
Total Revenues	1,175	756	(273)	1,658
Cost of natural gas and natural gas liquids	642	346	(271)	717
Operation and maintenance, General and administrative	205	140	(2)	343
Depreciation and amortization	154	94	—	248
Impairments	8	—	—	8
Taxes other than income tax	24	19	—	43
Operating income	$142	$ 157	$ —	$299
Total assets as of December 31, 2016	$7,453	$ 4,963	$ (1,204)	$11,212
Capital expenditures	$252	$ 37	$ —	$289

(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 nine months ended September 30, 2017 and 2016.

(15) Subsequent Event

On October 4, 2017, the Partnership acquired all of the equity interests in Align Midstream, LLC, a midstream company with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin, for approximately $300 million, subject to certain post-closing adjustments. The acquisition will be treated as a business combination and was funded with borrowings under the Revolving Credit Facility. Due to the timing of the acquisition, the Partnership has not yet completed its initial accounting analysis. As a result, the Partnership is unable to provide amounts recognized as of the acquisition date for major classes of assets and liabilities acquired and resulting from the transaction, including any intangible assets or goodwill.

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

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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.

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

Acquisition of Align Midstream

On October 4, 2017, the Partnership completed the acquisition of Align Midstream, LLC, a midstream company with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin, for approximately $300 million, subject to certain customary post-closing adjustments. The acquisition includes approximately 190 miles of natural gas gathering pipelines across Rusk, Panola and Shelby counties in Texas and DeSoto Parish in Louisiana and a cryogenic natural gas processing plant in Panola County, Texas, with a capacity of 100 MMcf/d. These assets are underpinned with long-term, fee-based contracts, including approximately 100,000 gross acres of dedication from producer customers.

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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 nine months ended September 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.

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 2019.

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

As previously disclosed, CenterPoint Energy has announced that it is evaluating strategic alternatives for its investment in Enable. CenterPoint Energy has disclosed that the alternatives may include a sale of all or a portion of the interests that it owns in Enable and Enable GP, that if the sale option is not viable it intends to reduce its ownership in Enable over time through a sale of the Enable common units it holds in the public equity markets subject to market conditions, and that there can be no assurances that these evaluations will result in any specific action.

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Results of Operations

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

Three Months Ended September 30, 2017	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$357	$ 152	$ (113)	$ 396
Service revenue	185	125	(1)	309
Total Revenues	542	277	(114)	705
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	308	154	(113)	349
Gross margin [(1)]	234	123	(1)	356
Operation and maintenance, General and administrative	70	45	(1)	114
Depreciation and amortization	56	34	—	90
Taxes other than income tax	9	6	—	15
Operating income	$99	$ 38	$ —	$ 137
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

Three Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$295	$ 150	$ (119)	$ 326
Service revenue	160	135	(1)	294
Total Revenues	455	285	(120)	620
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	246	141	(119)	268
Gross margin [(1)]	209	144	(1)	352
Operation and maintenance, General and administrative	63	46	(1)	108
Depreciation and amortization	53	31	—	84
Impairments	8	—	—	8
Taxes other than income tax	8	5	—	13
Operating income	$77	$ 62	$ —	$ 139
Equity in earnings of equity method affiliate	$—	$ 8	$ —	$ 8

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Nine Months Ended September 30, 2017	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,044	$ 439	$ (347)	$ 1,136
Service revenue	469	395	(3)	861
Total Revenues	1,513	834	(350)	1,997
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	863	421	(348)	936
Gross margin [1]	650	413	(2)	1,061
Operation and maintenance, General and administrative	215	135	(2)	348
Depreciation and amortization	167	100	—	267
Taxes other than income tax	27	20	—	47
Operating income	$241	$ 158	$ —	$ 399
Equity in earnings of equity method affiliate	$—	$ 21	$ —	$ 21

Nine Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$759	$ 348	$ (270)	$ 837
Service revenue	416	408	(3)	821
Total Revenues	1,175	756	(273)	1,658
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	642	346	(271)	717
Gross margin [1]	533	410	(2)	941
Operation and maintenance, General and administrative	205	140	(2)	343
Depreciation and amortization	154	94	—	248
Impairments	8	—	—	8
Taxes other than income tax	24	19	—	43
Operating income	$142	$ 157	$ —	$ 299
Equity in earnings of equity method affiliate	$—	$ 22	$ —	$ 22

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

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Operating Data:				
Gathered volumes—TBtu	325	291	922	851
Gathered volumes—TBtu/d	3.52	3.16	3.38	3.11
Natural gas processed volumes—TBtu	174	164	516	487
Natural gas processed volumes—TBtu/d	1.90	1.78	1.89	1.78
NGLs produced—MBbl/d (1)	84.48	77.53	84.02	78.08
NGLs sold—MBbl/d (1)(2)	86.83	73.45	84.10	77.93
Condensate sold—MBbl/d	3.75	4.11	4.75	5.54
Crude Oil—Gathered volumes—MBbl/d	28.87	23.78	24.44	26.03
Transported volumes—TBtu	445	441	1,383	1,352
Transported volumes—TBtu/d	4.83	4.79	5.05	4.92
Interstate firm contracted capacity—Bcf/d	5.62	6.89	6.35	7.00
Intrastate average deliveries—TBtu/d	1.90	1.77	1.86	1.72

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Anadarko				
Gathered volumes—TBtu/d	1.72	1.66	1.75	1.64
Natural gas processed volumes—TBtu/d	1.57	1.50	1.56	1.45
NGLs produced—MBbl/d (1)	70.85	65.24	70.99	64.53
Arkoma				
Gathered volumes—TBtu/d	0.53	0.61	0.55	0.63
Natural gas processed volumes—TBtu/d	0.09	0.10	0.09	0.10
NGLs produced—MBbl/d (1)	4.85	4.69	4.77	4.90
Ark-La-Tex				
Gathered volumes—TBtu/d	1.27	0.89	1.08	0.84
Natural gas processed volumes—TBtu/d	0.24	0.18	0.24	0.23
NGLs produced—MBbl/d (1)	8.78	7.60	8.26	8.65

(1) Excludes condensate.

Gathering and Processing

Three Months Ended September 30, 2017 compared to three months ended September 30, 2016. Our gathering and processing segment reported operating income of $99 million for the three months ended September 30, 2017 compared to operating income of $77 million for the three months ended September 30, 2016. The difference of $22 million in operating income between periods was primarily due to a $25 million increase in gross margin and no impairments in the three months ended September 30, 2017 as compared to $8 million of impairments in the three months ended September 30, 2016. This was partially offset by a $7 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 September 30, 2017.

Our gathering and processing segment revenues increased $87 million. The increase was primarily due to a $68 million increase in revenues from NGL sales resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $14 million increase in natural gas gathering revenues due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins and a $9 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 fourth quarter of 2016. These increases

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were partially offset by a $9 million decrease in revenues from changes in the fair value of condensate and NGL derivatives, a $5 million decrease in revenues from sales of natural gas and a $1 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 $25 million. The increase was primarily due to a $14 million increase in gathering margin due to increased gathered volumes in the Anadarko and Ark-La-Tex Basins and increased billings under minimum volume commitments, an $11 million increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin and an $8 million increase in natural gas sales due to higher average natural gas prices and higher volumes in the Anadarko and Ark-La-Tex Basins. These increases were partially offset by a $9 million decrease in gross margin from changes in the fair value of condensate and NGL derivatives and a $1 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 $7 million. The increase was primarily due to a $3 million increase due to a reduction in capitalized overhead costs, a $1 million increase in payroll-related costs, a $1 million increase in employee expenses, a $1 million increase in materials and supplies expense and a $1 million increase in the allowance for doubtful accounts.

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

Our gathering and processing segment recognized no impairments in the three months ended September 30, 2017 as compared to $8 million of impairments in the three months ended September 30, 2016 on our Service Star business line.

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.

Nine months ended September 30, 2017 compared to nine months ended September 30, 2016. Our gathering and processing segment reported operating income of $241 million for the nine months ended September 30, 2017 compared to operating income of $142 million for the nine months ended September 30, 2016. The difference of $99 million in operating income between periods was primarily due to a $117 million increase in gross margin and no impairments in the three months ended September 30, 2017 as compared to $8 million of impairments in the three months ended September 30, 2016. This was partially offset by a $13 million increase in depreciation and amortization, a $10 million increase in operation and maintenance and general and administrative expenses and a $3 million increase in taxes other than income tax during the nine months ended September 30, 2017.

Our gathering and processing segment revenues increased $338 million. The increase was primarily due to a $187 million increase in revenues from NGL sales resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $79 million increase in revenues from sales of natural gas as a result of higher average natural gas prices and higher gathering volumes in the Anadarko and Ark-La-Tex Basins, a $26 million increase in natural gas gathering revenues due to higher fees and gathered volumes in the Anadarko Basin and increased billings under minimum volume commitments in the Arkoma Basin, a $23 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 fourth quarter of 2016, a $22 million increase in revenues from changes in the fair value of condensate and NGL derivatives and a $2 million increase in revenues due to increased water transportation services in the Williston Basin. These increases were partially offset by a $3 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 $117 million. The increase was primarily due to a $44 million increase in natural gas sales due to higher average natural gas prices and higher gathering volumes in the Anadarko and Ark-La-Tex Basins, a $29 million increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $26 million increase in gathering margin due to increased gathered volumes in the Anadarko Basin and increased billings under minimum volume commitments in the Arkoma Basin, a $22 million increase in gross margin from changes in the fair value of condensate and NGL derivatives 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 $3 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 $10 million. The increase was primarily due to a $5 million increase in payroll-related costs, a $3 million increase due to a reduction in capitalized overhead costs, a $1 million increase in employee expenses and a $1 million increase in materials and supplies expense.

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Our gathering and processing segment depreciation and amortization increased $13 million due to additional assets placed in service.

Our gathering and processing segment recognized no impairments in the nine months ended September 30, 2017 as compared to $8 million of impairments in the nine months ended September 30, 2016 on our Service Star business line.

Our gathering and processing segment taxes other than income tax increased $3 million due to higher accrued ad valorem taxes due to additional assets placed in service.

Transportation and Storage

Three Months Ended September 30, 2017 compared to three months ended September 30, 2016. Our transportation and storage segment reported operating income of $38 million for the three months ended September 30, 2017 compared to operating income of $62 million for the three months ended September 30, 2016. The difference of $24 million in operating income between periods was primarily due to a $21 million decrease in gross margin, a $3 million increase in depreciation and amortization and a $1 million increase in taxes other than income, partially offset by a $1 million decrease in operation and maintenance and general and administrative expenses for the three months ended September 30, 2017.

Our transportation and storage segment revenues decreased $8 million. The decrease was primarily due to an $11 million decrease in firm transportation services between Carthage, Texas, and Perryville, Louisiana, a $5 million decrease in revenues from changes in the fair value of natural gas derivatives and a $1 million decrease in revenues from transportation services for LDCs. These decreases were partially offset by an increase of $3 million 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 NGL sales due to an increase in prices and volumes and a $2 million increase due to higher realized gains on natural gas derivatives.

Our transportation and storage segment gross margin decreased $21 million. The decrease was primarily due to an $11 million decrease in firm transportation services between Carthage, Texas and Perryville, Louisiana, an $11 million decrease in system management activities, a $5 million decrease in gross margin from changes in the fair value of natural gas derivatives and a $1 million decrease in margins from transportation services for LDCs. These decreases were partially offset by a $3 million increase in off-system transportation margins, a $2 million increase in realized gains on natural gas derivatives and a $1 million increase in NGL sales due to an increase in prices and volumes.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $1 million. The decrease was primarily due to a $2 million decrease in payroll-related costs, partially offset by a $1 million increase in various other operating costs.

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

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

Nine months ended September 30, 2017 compared to nine months ended September 30, 2016. Our transportation and storage segment reported operating income of $158 million in the nine months ended September 30, 2017 compared to operating income of $157 million in the nine months ended September 30, 2016. The difference of $1 million in operating income between periods was primarily due to a $3 million increase in gross margin and a $5 million decrease in operation and maintenance and general and administrative expenses, partially offset by a $6 million increase in depreciation and amortization and a $1 million increase in taxes other than income for the nine months ended September 30, 2017.

Our transportation and storage segment revenues increased $78 million. The increase was primarily due to a $47 million increase in revenues from changes in the fair value of natural gas derivatives, a $45 million increase in revenues from higher natural gas sales associated with higher sales volumes and higher average sales prices, a $7 million increase in revenues from NGL sales due to an increase in prices, a $6 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 $15 million decrease in firm transportation services between Carthage, Texas, and Perryville, Louisiana, a decrease of $8 million due to lower realized gains on natural gas derivatives and a $2 million decrease in revenues from transportation services for LDCs.

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Our transportation and storage segment gross margin increased $3 million. The increase was primarily due to a $47 million increase in gross margin from changes in the fair value of natural gas derivatives, a $6 million increase in off-system transportation margins, a $4 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 $32 million decrease in system management activities, a decrease of $15 million in firm transportation services between Carthage, Texas, and Perryville, Louisiana, a decrease of $8 million due to realized gains on natural gas derivatives as compared to realized losses in 2016 and a $2 million decrease in margins from transportation services for LDCs.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $5 million. The decrease was primarily due to a $4 million decrease in materials and supplies and contract services and a $2 million decrease in loss on sale of assets. These decreases were partially offset by a $1 million increase in payroll-related costs.

Our transportation and storage segment depreciation and amortization increased $6 million due to additional assets placed in service.

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

Condensed Consolidated Interim Information

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Operating Income	$137	$139	$399	$299
Other Income (Expense):				
Interest expense	(31)	(26)	(89)	(74)
Equity in earnings of equity method affiliate	7	8	21	22
Total Other Expense	(24)	(18)	(68)	(52)
Income Before Income Taxes	113	121	331	247
Income tax expense	—	2	2	3
Net Income	$113	$119	$329	$244
Less: Net income attributable to noncontrolling interest	—	—	1	—
Net Income Attributable to Limited Partners	$113	$119	$328	$244
Less: Series A Preferred Unit distributions	9	9	27	13
Net Income Attributable to Common and Subordinated Units	$104	$110	$301	$231

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

Net Income attributable to limited partners. We reported net income attributable to limited partners of $113 million in the three months ended September 30, 2017 compared to net income attributable to limited partners of $119 million in the three months ended September 30, 2016. The decrease in net income attributable to limited partners of $6 million was primarily attributable to an increase in interest expense of $5 million as well as a decrease in operating income of $2 million in the three months ended September 30, 2017.

Interest Expense. Interest expense increased $5 million primarily due to higher interest rates on the Partnership's outstanding debt.

Nine Months Ended September 30, 2017 compared to Nine Months Ended September 30, 2016

Net Income attributable to limited partners. We reported net income attributable to limited partners of $328 million in the nine months ended September 30, 2017 compared to net income attributable to limited partners of $244 million in the nine months ended September 30, 2016. The increase in net income attributable to limited partners of $84 million was primarily attributable to an increase in operating income of $100 million, partially offset by an increase in interest expense of $15 million in the nine months ended September 30, 2017.

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Interest Expense. Interest expense increased $15 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 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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Gross margin to Total Revenues:				
Consolidated				
Product sales	$396	$326	$1,136	$837
Service revenue	309	294	861	821
Total Revenues	705	620	1,997	1,658
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	349	268	936	717
Gross margin	$356	$352	$1,061	$941
Reportable Segments				
Gathering and Processing				
Product sales	$357	$295	$1,044	$759
Service revenue	185	160	469	416
Total Revenues	542	455	1,513	1,175
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	308	246	863	642
Gross margin	$234	$209	$650	$533
Transportation and Storage				
Product sales	$152	$150	$439	$348
Service revenue	125	135	395	408

Total Revenues	277	285	834	756
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	154	141	421	346
Gross margin	$123	$144	$413	$410

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

	Fee-Based Demand/ Commitment/ Guaranteed Return	Volume Dependent	Commodity-Based	Total
Nine Months Ended September 30, 2017				
Gathering and Processing Segment	29 %	45 %	26 %	100 %
Transportation and Storage Segment	87 %	7 %	6 %	100 %
Partnership Weighted Average	52 %	29 %	19 %	100 %

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	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	$113	$119	$328	$244
Depreciation and amortization expense	90	84	267	248
Interest expense, net of interest income	31	26	89	74
Income tax expense	—	2	2	3
Distributions received from equity method affiliate in excess of equity earnings	4	5	9	18
Non-cash equity-based compensation	4	4	12	9
Change in fair value of derivatives	6	(8)	(29)	40
Other non-cash losses[(1)]	2	4	8	11
Impairments	—	8	—	8
Adjusted EBITDA	$250	$244	$686	$655
Series A Preferred Unit distributions[(2)]	(9)	(9)	(27)	(22)
Distributions for phantom and performance units	(1)	—	(2)	—
Adjusted interest expense[(3)]	(31)	(27)	(90)	(76)
Maintenance capital expenditures	(22)	(21)	(53)	(51)
Current income taxes	—	2	—	1
DCF	$187	$189	$514	$507
Distributions related to common and subordinated unitholders[(4)]	$138	$134	$413	$402
Distribution coverage ratio	1.36	1.41	1.25	1.26

(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 nine months ended September 30, 2017 and 2016. The nine months ended September 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 September 30, 2017.

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	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In millions)			
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:				
Net cash provided by operating activities	$174	$209	$556	$498
Interest expense, net of interest income	31	26	89	74
Net income attributable to noncontrolling interest	—	—	(1)	—
Current income taxes	—	(2)	—	(1)
Other non-cash items[1]	—	3	2	4
Changes in operating working capital which (provided) used cash:				
Accounts receivable	100	47	72	25
Accounts payable	(30)	4	16	88
Other, including changes in noncurrent assets and liabilities	(35)	(40)	(28)	(91)
Return of investment in equity method affiliate	4	5	9	18
Change in fair value of derivatives	6	(8)	(29)	40
Adjusted EBITDA	$250	$244	$686	$655

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(1) Other non-cash items includes amortization of debt expense, discount and premium on long-term debt and write-downs of materials and supplies.

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In millions)			
Reconciliation of Adjusted interest expense to Interest expense:				
Interest Expense	$31	$ 26	$89	$74
Amortization of premium on long-term debt	1	1	4	4
Capitalized interest on expansion capital	—	—	—	1
Amortization of debt expense and discount	(1)	—	(3)	(3)
Adjusted interest expense	$31	$ 27	$90	$76

Liquidity and Capital Resources

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of September 30, 2017, we had a working capital deficit of $385 million. The deficit is primarily due to the classification of the 2015 Term Loan Agreement as Current portion of long-term debt as of September 30, 2017. We utilize our revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits.

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Cash Flows

The following tables reflect cash flows for the applicable periods:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In millions)	
Net cash provided by operating activities	$556	$498
Net cash used in investing activities	$(240)	$(270)
Net cash used in financing activities	$(317)	$(209)

Operating Activities

The increase of $58 million, or 12%, in net cash provided by operating activities for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016 was primarily due to an increase in net income of $85 million.

Investing Activities

The decrease of $30 million, or 11%, in net cash used in investing activities for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016 was primarily due to lower capital expenditures of $39 million partially offset by a decrease in return of investment in equity method affiliate of $9 million.

Financing Activities

Net cash used in financing activities increased $108 million for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016. Our primary financing activities consist of the following:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(In millions)	
Proceeds from 2027 Notes, net of issuance costs	$691	$ —
Net (repayments) proceeds from Revolving Credit Facility	(563)	445
Repayments from commercial paper program	—	(236)
Repayment of notes payable—affiliated companies	—	(363)
Proceeds from issuance of Series A Preferred Units, net of issuance costs	—	362
Distributions	(443)	(417)
Cash taxes paid for employee equity-based compensation	(2)	—

Please see Note 7, “Debt” in the Notes to the Unaudited Condensed Consolidated Financial Statements in Part 1, Item 1. for a description of the Partnership’s debt agreements.

Sources of Liquidity

As of September 30, 2017, our sources of liquidity included:

- cash on hand;
- cash generated from operations;
- borrowings under our Revolving Credit Facility; and
- capital raised through debt and equity markets.

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Distribution Reinvestment Plan

In June 2016, the Partnership implemented a Distribution Reinvestment Plan (DRIP), which, beginning with the quarterly distribution for the quarter ended September 30, 2016, 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. The Partnership will have the sole discretion to determine whether common units purchased under the DRIP will come from our newly issued common units or from common units purchased on the open market. The purchase price for newly issued common units will be the average of the high and low trading prices of the common units on the New York Stock Exchange-Composite Transactions for the five trading days immediately preceding the investment date. The purchase price for common units purchased on the open market will be the weighted average price of all common units purchased for the DRIP for the respective investment date. We can set a discount ranging from 0% to 5% for common units purchased pursuant to the DRIP. The discount is currently set at 0%. Participation in the DRIP is voluntary, and once enrolled, our unitholders may terminate participation at any time.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. Going forward, our capital requirements will consist of the following:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long-term, our operating capacity or operating income; and
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Our future expansion capital expenditures may vary significantly from period to period based on commodity prices and the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under our Revolving Credit Facility, new debt offerings or the issuance of additional partnership units. Issuances of equity or debt in the capital markets may not, however, be available to us on acceptable terms.

Distributions

On October 31, 2017, the board of directors of Enable GP declared a quarterly cash distribution of $0.318 per common unit on all of the Partnership’s outstanding common units for the period ended September 30, 2017. The distributions will be paid November 21, 2017 to unitholders of record as of the close of business on November 14, 2017. Additionally, the board of directors of Enable GP declared a quarterly cash distribution of $0.625 on the Partnership’s outstanding Series A Preferred Units. The distributions will be paid November 14, 2017 to unitholders of record as of the close of business on October 31, 2017.

Expiration of Subordination Period

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

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Credit Risk

We are exposed to certain credit risks relating to our ongoing business operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses. We examine the creditworthiness of third party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees.

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Critical Accounting Policies and Estimates

The Partnership’s critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 1 of the Notes to the Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data” in our Annual Report on Form 10-K for the year ended December 31, 2016. The accounting policies and estimates used in preparing our interim Condensed Consolidated Financial Statements for the three months ended September 30, 2017 are the same as those described in our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, including volatility in commodity prices and interest rates.

Commodity Price Risk

While we generate a substantial portion of our gross margin pursuant to fee-based contracts that include minimum volume commitments and/or demand fees, we are also directly and indirectly exposed to changes in the prices of natural gas, condensate and NGLs. The Partnership utilizes derivatives and forward commodity sales to mitigate the effects of price changes. We do not enter into risk management contracts for speculative purposes. For further information regarding our derivatives, see Note 8.

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately 16% of our total gross margin for the twelve months ending December 31, 2017 is directly exposed to changes in commodity prices, excluding the impact of hedges and contractual floors related to commodity prices in certain agreements.

Commodity price risk is estimated as the potential loss in value resulting from a hypothetical 10% decline in prices over the next six months. Based on a sensitivity analysis, a 10% decrease in prices from forecasted levels would decrease net income by approximately $3 million for natural gas and ethane and $3 million for NGLs, excluding ethane and condensate, excluding the impact of hedges, for the remaining three months ending December 31, 2017.

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is substantially comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher interest costs. Borrowings under our Revolving Credit Facility, 2015 Term Loan Agreement and any issuances under our commercial paper program are at a variable interest rate and expose us to the risk of increasing interest rates. Based upon the $523 million outstanding borrowings under the 2015 Term Loan Agreement and Revolving Credit Facility as of September 30, 2017, and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $5 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the

Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of September 30, 2017. Based on such evaluation, our management has concluded that, as of September 30, 2017, our disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms and that information is accumulated and communicated to our management, including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and

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procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control Over Financial Reporting

During the three months ended September 30, 2017, the Partnership completed the implementation of natural gas and natural gas liquid marketing and risk management systems. The systems were implemented by the Partnership to improve standardization and not in response to any deficiency in internal control over financial reporting. Management believes the implementation of the systems and related changes to internal controls will enhance the Partnership's internal controls over financial reporting. Management believes the necessary steps have been taken to monitor and maintain appropriate internal control over financial reporting during this period of change and will continue to evaluate the operating effectiveness of related key controls during subsequent periods.

There were no other changes in our internal controls over financial reporting during the quarter ended September 30, 2017, that have materially affected, or that are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding legal proceedings is set forth in Note 12 - Commitments and Contingencies to the Partnership’s condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report on Form 10-Q and is incorporated herein by reference.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. Risk factors relating to the Partnership are set forth under “Risk Factors” in our Annual Report. No other material changes to such risk factors have occurred during the three and nine months ended September 30, 2017.

Item 6. Exhibits

The following exhibits are filed herewith:

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Management contracts and compensatory plans and arrangements are designated by a star (*).

Agreements included as exhibits are included only to provide information to investors regarding their terms. Agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and no such agreement should be relied upon as constituting or providing any factual disclosures about Enable Midstream Partners, LP, any other persons, any state of affairs or other matters.

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2.1	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192545	Exhibit 2.1
3.1	Certificate of Limited Partnership of CenterPoint Energy Field Services LP, as amended	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192545	Exhibit 3.1
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Registrant's Form 8-K filed June 22, 2016	File No. 001-36413	Exhibit 3.1
4.1	Specimen Unit Certificate representing common units (included with Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP as Exhibit A thereto)	Registrant's Form 8-K filed April 22, 2014	File No. 001-36413	Exhibit 3.1
4.2	Indenture, dated as of May 27, 2014, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.1
4.3	First Supplemental Indenture, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.2
4.4	Registration Rights Agreement, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers.	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.3
4.5	Registration Rights Agreement, dated as of February 18, 2016, by and between Enable Midstream Partners, LP and CenterPoint Energy, Inc.	Registrant's Form 8-K filed February 19, 2016	File No. 001-36413	Exhibit 4.1
4.6	Second Supplemental Indenture, dated as of March 9, 2017, by and among Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed March 9, 2017	File No. 001-36413	Exhibit 4.2
+31.1	Rule 13a-14(a)/15d-14(a) Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
+31.2	Rule 13a-14(a)/15d-14(a) Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
+32.1	Section 1350 Certification of principal executive officer			
+32.2	Section 1350 Certification of principal financial officer			
+101.INS	XBRL Instance Document.			

+101.SCH	XBRL Taxonomy Schema Document.
+101.PRE	XBRL Taxonomy Presentation Linkbase Document.
+101.LAB	XBRL Taxonomy Label Linkbase Document.
+101.CAL	XBRL Taxonomy Calculation Linkbase Document.
+101.DEF	XBRL Definition Linkbase Document.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

		ENABLE MIDSTREAM PARTNERS, LP (Registrant)	
		By: ENABLE GP, LLC Its general partner	
Date:	November 1, 2017	By:	/s/ Tom Levescy Tom Levescy Senior Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)