Enable Midstream Partners, LP
Form 10-Q
November 07, 2018
Table of Contents

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

FORM 10-Q

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). 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	¨	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 12, 2018, there were 433,219,959 common units outstanding.

Table of Contents

ENABLE MIDSTREAM PARTNERS, LP
FORM 10-Q
TABLE OF CONTENTS

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.

Table of Contents

GLOSSARY OF TERMS

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

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

Table of Contents

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

Table of Contents

FORWARD-LOOKING STATEMENTS

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

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

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

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

Table of Contents

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,	
	2018	2017	2018	2017
	(In millions, except per unit data)			
Revenues (including revenues from affiliates (Note 12)):				
Product sales	$553	$396	$1,497	$1,136
Service revenues	375	309	984	861
Total Revenues	928	705	2,481	1,997
Cost and Expenses (including expenses from affiliates (Note 12)):				
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	516	349	1,335	936
Operation and maintenance	98	91	289	277
General and administrative	28	23	81	71
Depreciation and amortization	100	90	292	267
Taxes other than income tax	15	15	48	47
Total Cost and Expenses	757	568	2,045	1,598
Operating Income	171	137	436	399
Other Income (Expense):				
Interest expense	(40)	(31)	(109)	(89)
Equity in earnings of equity method affiliate	7	7	20	21
Other, net	1	—	1	—
Total Other Expense	(32)	(24)	(88)	(68)
Income Before Income Tax	139	113	348	331
Income tax expense	—	—	—	2
Net Income	$139	$113	$348	$329
Less: Net income attributable to noncontrolling interest	1	—	1	1
Net Income Attributable to Limited Partners	$138	$113	$347	$328
Less: Series A Preferred Unit distributions (Note 6)	9	9	27	27
Net Income Attributable to Common and Subordinated Units (Note 5)	$129	$104	$320	$301
Basic earnings per unit (Note 5)				
Common units	$0.30	$0.24	$0.74	$0.70
Subordinated units	$—	$0.24	$—	$0.69
Diluted earnings per unit (Note 5)				
Common units	$0.30	$0.24	$0.73	$0.69
Subordinated units	$—	$0.24	$—	$0.69

See Notes to the Unaudited Condensed Consolidated Financial Statements

Table of Contents

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

	September 30, 2018	December 31, 2017
	(In millions)	
Current Assets:		
Cash and cash equivalents	$8	$ 5
Restricted cash (Note 1)	14	14
Accounts receivable, net of allowance for doubtful accounts (Note 1)	333	277
Accounts receivable—affiliated companies	20	18
Inventory	45	40
Gas imbalances	25	37
Other current assets	36	25
Total current assets	481	416
Property, Plant and Equipment:		
Property, plant and equipment	12,633	12,079
Less accumulated depreciation and amortization	1,963	1,724
Property, plant and equipment, net	10,670	10,355
Other Assets:		
Intangible assets, net	418	451
Goodwill	12	12
Investment in equity method affiliate	313	324
Other	41	35
Total other assets	784	822
Total Assets	$11,935	$ 11,593
Current Liabilities:		
Accounts payable	$259	$ 263
Accounts payable—affiliated companies	3	3
Current portion of long-term debt	500	450
Short-term debt	413	405
Taxes accrued	51	32
Gas imbalances	20	12
Other	157	114
Total current liabilities	1,403	1,279
Other Liabilities:		
Accumulated deferred income taxes, net	6	6
Regulatory liabilities	22	21
Other	56	38
Total other liabilities	84	65
Long-Term Debt	2,880	2,595
Commitments and Contingencies (Note 13)		
Partners’ Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at September 30, 2018 and December 31, 2017)	362	362
Common units (433,216,156 issued and outstanding at September 30, 2018 and 432,584,080 issued and outstanding at December 31, 2017, respectively)	7,195	7,280
Noncontrolling interest	11	12
Total Partners’ Equity	7,568	7,654

Total Liabilities and Partners' Equity	$11,935	$ 11,593

See Notes to the Unaudited Condensed Consolidated Financial Statements

Table of Contents

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

	Nine Months Ended September 30,	
	2018	2017
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$348	$329
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	292	267
Deferred income taxes	—	2
Loss on sale/retirement of assets	1	7
Equity in earnings of equity method affiliate	(20)	(21)
Return on investment in equity method affiliate	20	21
Equity-based compensation	12	12
Amortization of debt costs and discount (premium)	(1)	(1)
Changes in other assets and liabilities:		
Accounts receivable, net	(56)	(72)
Accounts receivable—affiliated companies	(2)	—
Inventory	(5)	1
Gas imbalance assets	12	25
Other current assets	(19)	(5)
Other assets	(6)	2
Accounts payable	(19)	(16)
Gas imbalance liabilities	8	(17)
Other current liabilities	55	17
Other liabilities	18	5
Net cash provided by operating activities	638	556
Cash Flows from Investing Activities:		
Capital expenditures	(551)	(250)
Proceeds from sale of assets	8	1
Proceeds from insurance	1	—
Return of investment in equity method affiliate	11	9
Net cash used in investing activities	(531)	(240)
Cash Flows from Financing Activities:		
Repayment of long-term debt	(450)	—
Increase in short-term debt	8	—
Proceeds from long-term debt, net of issuance costs	787	691
Proceeds from Revolving Credit Facility	—	591
Repayment of Revolving Credit Facility	—	(1,154)
Proceeds from issuance of common units, net of issuance costs	2	—
Distributions	(442)	(443)
Cash paid for employee equity-based compensation	(9)	(2)
Net cash used in financing activities	(104)	(317)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	3	(1)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	19	23

Cash, Cash Equivalents and Restricted Cash at End of Period	$22	$22

See Notes to the Unaudited Condensed Consolidated Financial Statements

Table of Contents

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

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
	(In millions)							
Balance as of December 31, 2016	15	$362	224	$3,737	208	$3,683	$ 12	$7,794
Net income	—	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
Balance as of December 31, 2017	15	$362	433	$7,280	—	$—	$ 12	$7,654
Net income	—	27	—	320	—	—	1	348
Issuance of common units	—	—	—	2	—	—	—	2
Distributions	—	(27)	—	(413)	—	—	(2)	(442)
Equity-based compensation, net of units for employee taxes	—	—	—	6	—	—	—	6
Balance as of September 30, 2018	15	$362	433	$7,195	—	$—	$ 11	$7,568

See Notes to the Unaudited Condensed Consolidated Financial Statements
7

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

(1) Summary of Significant Accounting Policies

Organization

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

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

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

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

Basis of Presentation

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

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

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

Use of Estimates

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

Table of Contents

Restricted Cash

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

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, management evaluates our customers' financial strength based on aging of accounts receivable, payment history, and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $1 million allowance for doubtful accounts was required at September 30, 2018 and a $3 million allowance at December 31, 2017.

Inventory

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

Income Taxes

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

(2) New Accounting Pronouncements

Accounting Standards to be Adopted in Future Periods

Leases

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

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

Table of Contents

In July 2018, the FASB issued ASU No. 2018-10, “Codification Improvements to Topic 842, Leases” to address implementation issues that could arise as organizations comply with ASC 842.

In July 2018, the FASB issued ASU No. 2018-11, “Leases (Topic 842) - Targeted Improvements” to assist stakeholders with implementation questions and issues as organizations prepare to adopt ASC 842. These questions and issues relate primarily to (1) comparative reporting requirements for initial adoption; and (2) for lessors only, separating lease and non-lease components in a contract and allocating the consideration in the contract to the separate components.

The Partnership continues to review contracts and easements relative to the provisions of the ASU 2016-02 lease standard, the ASU 2018-01 easement standard, the ASU 2018-10 codification improvements standard and the ASU 2018-11 targeted improvements standard, as well as to monitor relevant emerging industry guidance regarding the implementation of the standards. As part of this analysis, we are evaluating the potential information technology and internal control changes that will be required for adoption based on the findings from our contract and easement review process. While we have not estimated the quantitative effect that ASC 842 will have on our consolidated financial statements, the adoption of ASC 842 will increase our asset and liability balances on the consolidated balance sheets due to the required recognition of right-of-use assets and corresponding lease liabilities for all lease obligations that are currently classified as operating leases. The Partnership will adopt these standards in the first quarter of 2019 and continues to evaluate the other impact of the standards on our Condensed Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

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

Compensation—Stock Compensation

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

Fair Value Measurement—Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, “Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement” which focuses on improving the effectiveness of disclosures in the notes to the financial statements by facilitating clear communication of the information required by U.S. GAAP that is most important to users of each entity’s financial statements. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted. The Partnership expects to adopt these standards in the first quarter of 2020 and continues to evaluate the other impacts of the new standards on our Condensed Consolidated Financial Statements and related disclosures.

Intangibles—Goodwill and Other—Internal-Use Software

In August 2018, the FASB issued ASU No. 2018-15, “Intangibles—Goodwill and Other—Internal-Use Software: Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract”, which aims to reduce complexity in the accounting for costs of implementing a cloud computing service arrangement. ASU No. 2018-15 aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The standard is effective for interim and annual periods beginning after December 15, 2019. The Partnership does not expect the adoption of this standard to have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

Table of Contents

(3) Revenues

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

The following tables disaggregate total revenues by major source from contracts with customers and the gain (loss) on derivative activity for the three and nine months ended September 30, 2018.

	Three Months Ended September 30, 2018			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$87	$ 146	$ (120)	$113
Natural gas liquids	439	7	(7)	439
Condensate	25	—	—	25
Total revenues from natural gas, natural gas liquids, and condensate	551	153	(127)	577
Gain (loss) on derivative activity	(23)	—	(1)	(24)
Total Product sales	$528	$ 153	$ (128)	$553
Service revenues:				
Demand revenues	$92	$ 114	$ —	$206
Volume-dependent revenues	158	14	(3)	169
Total Service revenues	$250	$ 128	$ (3)	$375
Total Revenues	$778	$ 281	$ (131)	$928

	Nine Months Ended September 30, 2018			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$299	$ 420	$ (336)	$383
Natural gas liquids	1,054	20	(20)	1,054
Condensate	98	—	—	98
Total revenues from natural gas, natural gas liquids, and condensate	1,451	440	(356)	1,535
Gain (loss) on derivative activity	(40)	2	—	(38)
Total Product sales	$1,411	$ 442	$ (356)	$1,497
Service revenues:				
Demand revenues	$194	$ 347	$ —	$541
Volume-dependent revenues	405	48	(10)	443
Total Service revenues	$599	$ 395	$ (10)	$984
Total Revenues	$2,010	$ 837	$ (366)	$2,481

Table of Contents

Product Sales

Natural Gas, NGLs or Condensate

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

Gain (Loss) on Derivative Activity

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

Service Revenues

Demand revenues

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

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

Volume-dependent revenues

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

Accounts Receivable

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

Table of Contents

	September 30, 2018	December 31, 2017
	(In millions)	
Accounts Receivable:		
Customers	$ 334	$ 265
Contract assets (1)	14	27
Non-customers	5	3
Total Accounts Receivable (2)	$ 353	$ 295

(1) Contract assets reflected in Total Accounts Receivable include accrued minimum volume commitments. Total Accounts Receivable does not include $2 million of contracts assets related to firm service transportation contracts with tiered rates, which are reflected in Other Assets.

(2) Total Accounts Receivable includes Accounts receivables, net of allowance for doubtful accounts and Accounts receivable—affiliated companies.

Contract Liabilities

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

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

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

	September 30, 2018	December 31, 2017	Amounts recognized in revenues
	(In millions)		
Deferred revenues	$ 44	$ 34	$ 18

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

	2018	2019	2020	2021	2022 and After
	(In millions)				
Deferred revenues	$ 16	$ 5	$ 5	$ 5	$ 13

Remaining Performance Obligations

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

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

	2018	2019	2020	2021

					2022 and After
	(In millions)				
Transportation and Storage	$121	$388	$282	$156	$776
Gathering and Processing	72	281	160	136	599
Total remaining performance obligations	$193	$669	$442	$292	$1,375

13

Table of Contents

Impact of Adoption

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

- Natural gas and natural gas liquids purchase arrangements - For certain arrangements within our gathering and processing segment, the Partnership purchases and controls the entire hydrocarbon stream at the point of receipt. As of January 1, 2018, these arrangements are considered supplier contracts rather than contracts with customers. Therefore, beginning January 1, 2018, the gathering and processing fees for these arrangements that were previously recognized as Service revenues under ASC 605 are recognized as reductions to Cost of natural gas and natural gas liquids.
- Percent-of-proceeds and percent-of-liquids processing arrangements - Under percent-of-proceeds and percent-of-liquids arrangements within our gathering and processing segment, the Partnership has previously recognized the value of natural gas and natural gas liquids received in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the natural gas and NGLs received as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the natural gas or NGLs are sold and Product sales are recognized.
- Keep-whole arrangements - Under keep-whole arrangements within our gathering and processing segment, the Partnership has previously recognized the value of NGLs received in Product sales and the value of the thermally equivalent quantity of natural gas provided in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the NGLs received less the value of the thermal equivalent volume of natural gas provided as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the NGLs are sold and Product sales are recognized.
- Fixed fuel arrangements - Under certain gathering arrangements within our gathering and processing segment as well as under certain transportation arrangements within our transportation and storage segment we receive a fixed amount of fuel regardless of actual fuel usage. Previously, revenue for fuel in excess of actual usage was recognized when such fuel was received, and additional revenue was recognized when such fuel was sold. As of January 1, 2018, fuel in excess of actual usage is treated as a byproduct obtained through the fulfillment of a contract, and the Partnership will recognize revenue at the time the excess fuel is sold. This results in a reduction of Product sales and a corresponding reduction in Cost of natural gas and natural gas liquids.
- Natural gas and natural gas liquids sales arrangements - For certain arrangements within our gathering and processing segment, the Partnership sells the entire hydrocarbon stream at the point of delivery to a third-party processing facility. As of January 1, 2018, these arrangements are considered sales once control has transferred to the third-party processing facility. Therefore, beginning January 1, 2018, the transportation and fractionation fees for these arrangements that were previously recognized as a component of cost of gas and natural gas liquids, are recognized as reductions to the transaction price under ASC 606.

Table of Contents

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

	Three Months Ended September 30, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
	(In millions)		
Revenues:			
Product sales:			
Natural gas	$113	$143	$ (30)
Natural gas liquids	439	446	(7)
Condensate	25	25	—
Total revenues from natural gas, natural gas liquids, and condensate	577	614	(37)
Gain (loss) on derivative activity	(24)	(24)	—
Total Product sales	$553	$590	$ (37)
Service revenues:			
Demand revenues	$206	$197	9
Volume-dependent revenues	169	155	14
Total Service revenues	$375	$352	$ 23
Total Revenues	$928	$942	$ (14)

	Nine Months Ended September 30, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
	(In millions)		
Revenues:			
Product sales:			
Natural gas	$383	$437	$ (54)
Natural gas liquids	1,054	1,073	(19)
Condensate	98	98	—
Total revenues from natural gas, natural gas liquids, and condensate	1,535	1,608	(73)
Gain (loss) on derivative activity	(38)	(38)	—
Total Product sales	$1,497	$1,570	$ (73)
Service revenues:			
Demand revenues	$541	$532	9
Volume-dependent revenues	443	428	15
Total Service revenues	$984	$960	$ 24
Total Revenues	$2,481	$2,530	$ (49)

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

Table of Contents

(4) Acquisition

Align Acquisition

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

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

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

In connection with the acquisition, the Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 10 years. Goodwill recognized from the acquisition primarily relates to greater operating leverage in the Ark-La-Tex Basin and is allocated to the gathering and processing segment. The Partnership incurred approximately $2 million of acquisition costs associated with this transaction, which were included in General and administrative expense in the Consolidated Statements of Income in the fourth quarter of 2017. The Partnership determined not to include pro forma consolidated financial statements for the periods presented as the impact would not be material.

Table of Contents

(5) Earnings Per Limited Partner Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions, except per unit data)			
Net income	$139	$113	$348	$329
Net income attributable to noncontrolling interest	1	—	1	1
Series A Preferred Unit distributions	9	9	27	27
General partner interest in net income	—	—	—	—
Net income available to common and subordinated unitholders	$129	$104	$320	$301
Net income allocable to common units	$129	$71	$320	$174
Net income allocable to subordinated units	—	33	—	127
Net income available to common and subordinated unitholders	$129	$104	$320	$301
Net income allocable to common units	$129	$71	$320	$174
Dilutive effect of Series A Preferred Unit distributions	—	—	—	—
Diluted net income allocable to common units	129	71	320	174
Diluted net income allocable to subordinated units	—	33	—	127
Total	$129	$104	$320	$301
Basic weighted average number of outstanding				
Common units [(1)]	435	298	434	250
Subordinated units	—	136	—	183
Total	435	434	434	433
Basic earnings per unit				
Common units	$0.30	$0.24	$0.74	$0.70
Subordinated units	$—	$0.24	$—	$0.69
Basic weighted average number of outstanding common units	435	298	434	250
Dilutive effect of Series A Preferred Units	—	—	—	—
Dilutive effect of performance units	1	1	2	1
Diluted weighted average number of outstanding common units	436	299	436	251
Diluted weighted average number of outstanding subordinated units	—	136	—	183
Total	436	435	436	434
Diluted earnings per unit				
Common units	$0.30	$0.24	$0.73	$0.69
Subordinated units	$—	$0.24	$—	$0.69

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

September 30, 2018, respectively, and one million time-based phantom units for each of the three and nine months ended September 30, 2017.

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

Table of Contents

(6) Partners' Equity

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

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

Three Months Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
September 30, 2018 [(1)]	November 16, 2018	November 29, 2018	$ 0.318	$ 138
June 30, 2018	August 21, 2018	August 28, 2018	$ 0.318	$ 138
March 31, 2018	May 22, 2018	May 29, 2018	$ 0.318	$ 138
December 31, 2017	February 20, 2018	February 27, 2018	$ 0.318	$ 138
September 30, 2017	November 14, 2017	November 21, 2017	$ 0.318	$ 138
June 30, 2017	August 22, 2017	August 29, 2017	$ 0.318	$ 138
March 31, 2017	May 23, 2017	May 30, 2017	$ 0.318	$ 137

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on November 6, 2018, to be paid on November 29, 2018, to common unitholders of record at the close of business on November 16, 2018.

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

Three Months Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
September 30, 2018 [(1)]	November 6, 2018	November 14, 2018	$ 0.625	$ 9
June 30, 2018	August 1, 2018	August 14, 2018	$ 0.625	$ 9
March 31, 2018	May 1, 2018	May 15, 2018	$ 0.625	$ 9
December 31, 2017	February 9, 2018	February 15, 2018	$ 0.625	$ 9
September 30, 2017	October 31, 2017	November 14, 2017	$ 0.625	$ 9
June 30, 2017	July 31, 2017	August 14, 2017	$ 0.625	$ 9
March 31, 2017	May 2, 2017	May 12, 2017	$ 0.625	$ 9

(1) The board of directors of Enable GP declared a $0.625 per Series A Preferred Unit cash distribution on November 6, 2018, to be paid on November 14, 2018, to Series A Preferred unitholders of record at the close of business on November 6, 2018.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units that they own.

Expiration of Subordination Period

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

Table of Contents

Series A Preferred Units

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

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

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

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

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

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

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

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

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement, pursuant to which the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. During the three and nine months ended September 30, 2018, the Partnership issued 140,920 common units, which generated proceeds of approximately $2 million (net of approximately $25,000 of commissions). During the nine months ended September 30, 2017, the Partnership issued 18,500 common units, which generated proceeds of approximately $303,000 (net of $3,000 of commissions). The proceeds were used for general partnership purposes. As of September 30, 2018, $197 million of common units remained available for issuance through the ATM Program.

Table of Contents

(7) Investment in Equity Method Affiliate

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

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

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. The Partnership billed SESH $6 million and $3 million during the three months ended September 30, 2018 and 2017, and $14 million during each of the nine months ended September 30, 2018 and 2017, respectively, associated with these service agreements.

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

SESH:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Equity in Earnings of Equity Method Affiliate	$7	$ 7	$ 20	$ 21
Distributions from Equity Method Affiliate [(1)]	$10	$ 11	$ 31	$ 30

(1) Distributions from equity method affiliate includes a $7 million and $7 million return on investment and a $3 million and $4 million return of investment for each of the three months ended September 30, 2018 and 2017, respectively. Distributions from equity method affiliate includes a $20 million and $21 million return on investment and an $11 million and $9 million return of investment for the nine months ended September 30, 2018 and 2017, respectively.

Summarized financial information of SESH:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Income Statements:				
Revenues	$29	$ 29	$ 85	$ 85
Operating income	$18	$ 18	$ 51	$ 53

Net income	$ 13	$ 14	$ 38	$ 40

Table of Contents

(8) Debt

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

	September 30, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)	Total Debt	Outstanding Principal	Premium (Discount)	Total Debt
	(In millions)					
Commercial Paper	$413	$ —	$413	$405	$ —	$405
Revolving Credit Facility	—	—	—	—	—	—
2015 Term Loan Agreement	—	—	—	450	—	450
2019 Notes	500	—	500	500	—	500
2024 Notes	600	—	600	600	—	600
2027 Notes	700	(2)	698	700	(3)	697
2028 Notes	800	(6)	794	—	—	—
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	8	258	250	13	263
Total debt	$3,813	$ —	$3,813	$3,455	$ 10	$3,465
Less: Short-term debt (1)			413			405
Less: Current portion of long-term debt (2)			500			450
Less: Unamortized debt expense (3)			20			15
Total long-term debt			$2,880			$2,595

(1) Short-term debt includes $413 million and $405 million of outstanding commercial paper as of September 30, 2018 and December 31, 2017, respectively.

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

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

Commercial Paper

The Partnership has a commercial paper program, pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There were $413 million and $405 million outstanding under our commercial paper program at September 30, 2018 and December 31, 2017, respectively. The weighted average interest rate for the outstanding commercial paper was 2.83% as of September 30, 2018.

Revolving Credit Facility

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

The Revolving Credit Facility provides that outstanding borrowings bear interest at the LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of September 30, 2018, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of September 30, 2018, the commitment fee under the restated Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Condensed Consolidated Statements of Income.

Table of Contents

Term Loan Agreement

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

Senior Notes

On May 10, 2018, the Partnership completed the public offering of $800 million aggregate principal amount of its 4.95% Senior Notes due 2028. The Partnership received net proceeds of approximately $787 million. The proceeds were used for general partnership purposes, including to repay all amounts outstanding under the 2015 Term Loan Agreement, as well as amounts outstanding under the commercial paper program. The 2028 Notes had an unamortized discount of $6 million and unamortized debt expense of $7 million at September 30, 2018, resulting in an effective interest rate of 5.21% during the nine months ended September 30, 2018.

In addition to the 2028 Notes, as of September 30, 2018, the Partnership’s debt included the 2019 Notes, 2024 Notes, 2027 Notes, and 2044 Notes, which had $2 million of unamortized discount and $13 million of unamortized debt expense at September 30, 2018, resulting in effective interest rates of 2.57%, 4.02%, 4.58% and 5.08%, respectively, during the nine months ended September 30, 2018.

As of September 30, 2018, the Partnership’s debt included $250 million aggregate principal amount of EOIT’s 6.25% senior notes due 2020. The EOIT Senior Notes had $8 million of unamortized premium at September 30, 2018, resulting in an effective interest rate of 3.82% during the nine months ended September 30, 2018.

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

(9) Derivative Instruments and Hedging Activities

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

Commodity Price Risk

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

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

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

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

Table of Contents

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

Credit Risk

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

Derivatives Not Designated As Hedging Instruments

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

Quantitative Disclosures Related to Derivative Instruments

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

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

	September 30, 2018		December 31, 2017	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas — TBtu[1]				
Financial fixed futures/swaps	18	17	17	13
Financial basis futures/swaps	21	30	17	17
Physical purchases/sales	1	62	1	37
Crude oil (for condensate) — MBbl[2]				
Financial futures/swaps	—	969	—	564
Financial swaptions[3]	—	30	—	—
Natural gas liquids — MBbl[4]				
Financial futures/swaps	—	3,190	—	1,615

(1) As of September 30, 2018, 80.8% of the natural gas contracts had durations of one year or less, 16.5% had durations of more than one year and less than two years and 2.7% had durations of more than two years. As of December 31, 2017, 67.7% of the natural gas contracts had durations of one year or less, 16.1% had durations of more than one year and less than two years and 16.2% had durations of more than two years.

(2) As of September 30, 2018, 67.0% of the crude oil (for condensate) contracts had durations of one year or less and 33.0% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the crude oil (for condensate) contracts had durations of one year or less.

(3) The notional contains a combined derivative instrument consisting of a fixed price swap and a sold option, which gives the counterparties the right, but not the obligation, to increase the notional quantity hedged under the fixed price swap until the option expiration date. The notional volume represents the volume prior to option exercise.

(4) As of September 30, 2018, 73.2% of the natural gas liquids contracts had durations of one year or less and 26.8% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the natural gas liquid contracts had durations of one year or less.

Table of Contents

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, 2018 and December 31, 2017 that were not designated as hedging instruments for accounting purposes are as follows:

		September 30, 2018		December 31, 2017	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current/Other	$2	$ 7	$ 5	$ 4
Physical purchases/sales	Other Current/Other	6	1	3	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current/Other	—	11	—	4
Financial swaptions	Other	—	—	—	—
Natural gas liquids					
Financial Futures/swaps	Other Current/Other	—	21	1	5
Total gross derivatives (1)		$8	$ 40	$ 9	$ 13

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

Income Statement Presentation Related to Derivative Instruments

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

	Amounts Recognized in Income			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Natural gas				
Financial futures/swaps (losses) gains	$(1)	$1	$(6)	$17
Physical purchases/sales gains	—	1	5	8
Crude oil (for condensate)				
Financial futures/swaps (losses) gains	(4)	(2)	(14)	3
Financial swaptions (losses) gains	—	—	—	—
Natural gas liquids				
Financial futures/swaps (losses) gains	(19)	(7)	(23)	(5)
Total	$(24)	$(7)	$(38)	$23

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

Table of Contents

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, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Change in fair value of derivatives	$(16)	$(6)	$(28)	$29
Realized gain (loss) on derivatives	(8)	(1)	(10)	(6)
Gain (loss) on derivative activity	$(24)	$(7)	$(38)	$23

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's senior unsecured debt rating to a below investment grade rating, the Partnership could be required to provide additional credit assurances to third parties, which could include letters of credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position. As of September 30, 2018, under these obligations, the Partnership has posted $9 million of cash collateral related to NGL swaps and crude swaps and swaptions and $17 million of additional collateral may be required to be posted by the Partnership in the event of a credit ratings downgrade to a below investment grade rating.

(10) Fair Value Measurements

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

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on either the NYMEX or the ICE and settled through either a NYMEX or ICE 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 generally include over-the-counter 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 or the ICE pricing, and over-the-counter WTI crude oil swaps and swaptions 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, ICE or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX or ICE published market prices may be considered Level 1 if they are settled through a NYMEX or ICE clearing broker account with daily margining. Over-the-counter derivatives with NYMEX, ICE 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. Certain derivatives with option features may be classified as Level 2 if valued using an industry standard Black-Scholes option pricing model that contain observable inputs in the marketplace throughout the term of the derivative instrument. 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, 2018, there were no transfers between levels.

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

Estimated Fair Value of Financial Instruments

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

	September 30, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2) [1]	$ —	$ —	$ —	$ —
2015 Term Loan Agreement (Level 2)	—	—	450	450
2019 Notes (Level 2)	500	498	500	497
2024 Notes (Level 2)	600	581	600	602
2027 Notes (Level 2)	698	670	697	712
2028 Notes (Level 2)	794	795	—	—
2044 Notes (Level 2)	550	494	550	550
EOIT Senior Notes (Level 2)	258	258	263	265

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. $413 million and $405 million of commercial paper was outstanding as of September 30, 2018 and December 31, 2017, respectively.

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

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

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

26

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, 2018 and December 31, 2017:

September 30, 2018	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$2	$ 6	$ —	$ —
Significant other observable inputs (Level 2)	6	34	16	19
Unobservable inputs (Level 3)	—	—	—	—
Total fair value	8	40	16	19
Netting adjustments	(2)	(2)	—	—
Total	$6	$ 38	$ 16	$ 19

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

---

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. There were no netting adjustments as of September 30, 2018 and December 31, 2017.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $9 million and $10 million at September 30, 2018 and December 31, 2017, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created, and which are not subject to revaluation at fair market value.

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

27

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. Transfers out of Level 3 represent liabilities that were previously classified as Level 3 for which the inputs became observable for classification in Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Partnership's derivative contracts is subject to change.

	Commodity Contracts Natural gas liquids financial futures/swaps
	(In millions)
Balance at December 31, 2017	$ (5)
Losses included in earnings	(23)
Settlements	7
Transfers out of Level 3	21
Balance as of September 30, 2018	$ —

(11) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Nine Months Ended September 30,	
	2018	2017
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 90	$ 77
Income taxes, net of refunds	3	—
Non-cash transactions:		
Accounts payable related to capital expenditures	56	52

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

	Nine Months Ended September 30,	
	2018	2017
	(In millions)	
Cash and cash equivalents	$ 8	$ 8

Restricted cash	14	14
Cash, cash equivalents and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 22	$ 22

(12) Related Party Transactions

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

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas; including, firm transportation with seasonal contract demand, firm storage, no notice transportation with associated storage and maximum

Table of Contents

rate firm transportation. Contracts for firm transportation with seasonal contract demand, firm storage, firm no notice transportation with storage for CenterPoint's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas are in effect through March 21, 2021 and will remain in effect thereafter unless and until terminated by either party upon 180 days' prior written notice. Contracts for maximum firm rate transportation for CenterPoint's LDCs in Oklahoma and portions of Northeast Texas are also in effect through March 21, 2021. Contracts for CenterPoint's LDCs in Arkansas, Louisiana and Texarkana, Texas terminated on March 31, 2018. MRT provides transportation and storage services to CenterPoint Energy's LDCs in Arkansas and Louisiana. Contracts for these services are in effect through May 15, 2023 and will remain in effect thereafter unless and until terminated by either party upon 12 months' prior written notice.

Transportation and Storage Agreement with OGE Energy

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

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

Gas Sales and Purchases Transactions

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Gas transportation and storage service revenues — CenterPoint Energy	$22	$ 22	$79	$79
Natural gas product sales — CenterPoint Energy	1	—	9	1
Gas transportation and storage service revenues — OGE Energy	9	9	27	27
Natural gas product sales — OGE Energy	1	2	3	2
Total revenues — affiliated companies	$33	$ 33	$118	$109

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,	
	2018	2017	2018	2017
	(In millions)			
Cost of natural gas purchases — CenterPoint Energy	$ —	$ —	$ 2	$ 1
Cost of natural gas purchases — OGE Energy	7	6	15	13
Total cost of natural gas purchases — affiliated companies	$ 7	$ 6	$ 17	$ 14

Table of Contents

Seconded employees, corporate services and operating lease expense

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

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

The Partnership leases office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease commenced on October 1, 2016 and extends through December 31, 2019. As of September 30, 2018, the Partnership expects to incur approximately $1 million in rent and maintenance expenses during the remaining term of the lease. As of September 30, 2018, CenterPoint Energy continues to provide data center space to the Partnership in Houston, Texas, under the services agreement; however, the Partnership has terminated the provision of office space and moved the Houston corporate office to office space leased from a third party.

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,	
	2018	2017	2018	2017
	(In millions)			
Corporate Services — CenterPoint Energy	$1	$ —	$ 2	$ 2
Operating Lease — CenterPoint Energy	—	1	—	1
Seconded Employee Costs — OGE Energy	6	7	21	23
Corporate Services — OGE Energy	—	1	1	3
Total corporate services and seconded employees expense	$7	$ 9	$ 24	$ 29

Series A Preferred Units

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

(13) Commitments and Contingencies

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

On January 1, 2017, the Partnership entered into a 10-year gathering and processing agreement, which became effective on July 1, 2018, with an affiliate of Energy Transfer Partners, LP for 400 MMcf/d of deliveries to the Godley Plant in Johnson County, Texas. As of September 30, 2018, the Partnership estimates the remaining associated 10-year minimum volume commitment fee to be $221 million.

On August 28, 2018, the Partnership entered into the Bank of Oklahoma Park Plaza lease to occupy 154,584 square feet of office space in Oklahoma City, Oklahoma, which ends June 30, 2029. The lease payments commence on July 1, 2019, and total

Table of Contents

$25 million over the lease term, as well as a proportionate percentage of facility expenses. The Partnership will relocate its headquarters to the new location during the third quarter of 2019. Minimum lease payments are expected to be $1 million in 2019 and $2 million per year from 2020 through 2023.

On September 13, 2018, the Partnership executed a precedent agreement for the development of the Gulf Run Pipeline, an interstate natural gas transportation project. Subject to a final investment decision by the cornerstone shipper and approval of the project by the FERC, the Partnership would be required to construct a large-diameter pipeline from northern Louisiana to Gulf Coast markets. In addition, the Partnership may transfer existing EGT transportation infrastructure to the Gulf Run Pipeline. Under the precedent agreement with a cornerstone shipper, the project is backed by a 20-year, 1.1 billion cubic feet per day of capacity firm transportation service. The Gulf Run Pipeline connects natural gas producing regions in the U.S., including the Haynesville, Marcellus, Utica and Barnett shales and the Mid-Continent region. The project is expected to be placed into service in 2022.

On November 1, 2018, the Partnership acquired the ownership interests in Velocity Holdings, LLC (Velocity), which owns and operates crude oil and condensate gathering and transportation system in the SCOOP and Merge plays of the Anadarko Basin, for approximately $442 million, subject to certain customary working capital adjustments. The acquisition will be treated as a business combination and was funded with borrowings under the commercial paper program. 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.

(14) Equity-Based Compensation

The following table summarizes the Partnership's compensation expense for the three and nine months ended September 30, 2018 and 2017 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,	
	2018	2017	2018	2017
	(In millions)			
Performance units	$2	$ 3	$ 7	$ 8
Restricted units	—	—	1	1
Phantom units	2	1	4	3
Total compensation expense	$4	$ 4	$ 12	$ 12

Table of Contents

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, 2018 and changes during 2018 are shown in the following table.

	Performance Units		Restricted Units		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)					
Units outstanding at December 31, 2017	2,040,407	$13.86	222,384	$17.87	987,380	$11.38
Granted (1)	538,205	17.70	—	—	526,181	14.15
Vested (2)	(401,772)	12.59	(206,068)	17.06	(19,642)	13.65
Forfeited	(71,664)	14.26	(1,316)	16.75	(52,280)	12.50
Units outstanding at September 30, 2018	2,105,176	$14.31	15,000	$23.56	1,441,639	$12.32
Aggregate intrinsic value of units outstanding at September 30, 2018	$35		$—		$24	

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

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

Unrecognized Compensation Cost

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

	September 30, 2018	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$14	1.16
Restricted Units	—	0.08
Phantom Units	9	1.36
Total	$23	

As of September 30, 2018, there were 7,578,088 units available for issuance under the long-term incentive plan.

(15) Reportable Segments

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

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

Table of Contents

(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, 2018	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$528	$ 153	$ (128)	$553
Service revenues	250	128	(3)	375
Total Revenues	778	281	(131)	928
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	493	152	(129)	516
Operation and maintenance, General and administrative	78	48	—	126
Depreciation and amortization	66	34	—	100
Taxes other than income tax	9	6	—	15
Operating income	$132	$ 41	$ (2)	$171
Capital expenditures	$125	$ 51	$ —	$176
Total assets	$9,371	$ 5,710	$ (3,146)	$11,935

Three Months Ended September 30, 2017	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$357	$ 152	$ (113)	$396
Service revenues	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
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
Capital expenditures	$86	$ 16	$ —	$102
Total assets as of December 31, 2017	$9,079	$ 5,616	$ (3,102)	$11,593

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

Table of Contents

Nine Months Ended September 30, 2018	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$1,411	$ 442	$ (356)	$1,497
Service revenues	599	395	(10)	984
Total Revenues	2,010	837	(366)	2,481
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,262	438	(365)	1,335
Operation and maintenance, General and administrative	230	141	(1)	370
Depreciation and amortization	191	101	—	292
Taxes other than income tax	29	19	—	48
Operating income	$298	$ 138	$ —	$436
Capital expenditures	$416	$ 135	$ —	$551
Total assets	$9,371	$ 5,710	$ (3,146)	$11,935

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 revenues	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
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
Capital expenditures	$176	$ 74	$ —	$250
Total assets as of December 31, 2017	$9,079	$ 5,616	$ (3,102)	$11,593

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

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

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

Table of Contents

Overview

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

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

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

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

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

Recent Developments

Regulatory Update

Interstate Natural Gas Transportation Regulation

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

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

Table of Contents

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

Included in the issuances on March 15, 2018, is a Notice of Proposed Rulemaking (NOPR) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information. The Final Rule states that this information will allow FERC and other stakeholders to evaluate the impacts of the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement on each individual pipeline’s rates. The Final Rule also requires that each FERC-regulated natural gas pipeline select one of four options: file a limited NGA Section 4 filing reducing its rates only as required in relation to the Tax Cuts and Jobs Act of 2017 and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the Commission clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. At this time, we cannot predict the outcome of the Final Rule, but FERC’s adoption of the regulation could impact the rates the Partnership’s FERC-regulated entities are permitted to charge their customers. EGT filed its Form No. 501-G on October 11, 2018.

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

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

MRT Rate Case

On June 29, 2018, MRT filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act. The rate case proposed, among other things, a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by MRT, a change in the boundary between the Field and Market zones, a requirement for daily balancing, and changes to the Small Customer service rate schedule. A number of customers filed notices of intervention and protests, and on July 31, 2018, FERC issued an Order Accepting and Suspending Tariff Records Subject to Refund and Condition and Establishing Hearing and Settlement Judge Procedures and a Technical Conference (July 31 Order). In the July 31 Order, the Commission ordered MRT

Table of Contents

to refile its rate case within 30 days of the date of the July 31 Order to reflect, among other things, the elimination of an income tax allowance from its costs used to calculate MRT's rates. On August 30, 2018, MRT submitted a filing implementing FERC's directives in the July 31 Order. The elimination of the income tax allowance as mandated by FERC, when coupled with the corresponding elimination of ADIT, had a de minimis impact on MRT's overall cost of service. MRT also has requested rehearing of the July 31 Order.

Interstate Crude Oil Transportation Regulation

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

Imposition of Ad Valorem Tariffs

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

Commercial and Construction Update

Project Wildcat Rich Gas Takeaway Solution

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

EGT and EOIT Expansion Projects

Newfield Exploration Company has entered into a 205,000 Dth/d firm natural gas transportation agreement with EGT related to the Cana and STACK Expansion (CaSE) project, a system expansion providing firm transportation service for growing Anadarko Basin production. The 10-year contract started at an initial capacity of 45,000 Dth/d in early 2018, achieved a contractual increase in volumes to 135,000 Dth/d in the second quarter of 2018, and achieved full capacity on October 1, 2018. The Muskogee project, a 20-year, 228,000 Dth/d firm transportation service agreement with a subsidiary of OGE Energy on the EOIT system, is expected to commence service by the end of 2018.

Table of Contents

Williston Basin System Expansion

On August 16, 2018, the Partnership entered into 15-year crude oil and water transportation agreements with ExxonMobil subsidiary XTO Energy Inc. ("XTO") to support XTO's development plans in the Bakken Shale formation of the Williston Basin. These agreements include the dedication of XTO's crude oil and water production to the Partnership's gathering systems from over 90,000 gross acres in North Dakota's Dunn and McKenzie counties. Subject to XTO's drilling plans, the Partnership will add up to 72 MBbl/d of design capacity to its Bear Den crude oil gathering system, increasing total system design capacity to up to approximately 130 MBbl/d. The Partnership expects to start gathering volumes under the new agreements in the first half of 2019.

Gulf Run Pipeline

On September 13, 2018, the Partnership executed a precedent agreement for the development of the Gulf Run Pipeline, an interstate natural gas transportation project. Subject to a final investment decision by the cornerstone shipper for the liquefied natural gas export facility to be served by this project and approval of the project by the FERC, the Partnership would be required to construct up to an estimated 165 miles of large-diameter pipeline from northern Louisiana to Gulf Coast markets. In addition, the Partnership may transfer existing EGT transportation infrastructure to the Gulf Run Pipeline. Under the precedent agreement with a cornerstone shipper, the project is backed by a 20-year, 1.1 billion cubic feet per day of capacity firm transportation service. The Gulf Run Pipeline connects natural gas producing regions in the U.S., including the Haynesville, Marcellus, Utica and Barnett shales and the Mid-Continent region. The project is expected to be placed into service in 2022.

Acquisition of Velocity Holdings

On November 1, 2018, the Partnership completed the acquisition of Velocity, which owns crude oil and condensate gathering, transportation, and storage terminal facilities in the SCOOP and Merge plays of the Anadarko Basin, for approximately $442 million, subject to certain customary working capital adjustments. Velocity operates approximately 150 miles of crude oil and condensate gathering and transportation pipelines across Grady, Stevens, Garvin and McClain counties in Oklahoma. A portion of Velocity's operations are conducted through a joint venture with Coffeyville Resources Pipeline, LLC and Velocity owns 60% of the joint venture and operates its assets. Crude oil from the system is delivered to the Wynnewood Refining Company's refinery at Wynnewood, Oklahoma and is also capable of being delivered to crude oil terminal facilities in Cushing, Oklahoma. Velocity's assets are underpinned with long-term, fee-based contracts.

CenterPoint Strategic Review

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

Liquidity Update

Second Amended and Restated Revolving Credit Facility

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

2028 Notes

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

Table of Contents

Results of Operations

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

Three Months Ended September 30, 2018	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$528	$ 153	$ (128)	$ 553
Service revenues	250	128	(3)	375
Total Revenues	778	281	(131)	928
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	493	152	(129)	516
Gross margin (1)	285	129	(2)	412
Operation and maintenance, General and administrative	78	48	—	126
Depreciation and amortization	66	34	—	100
Taxes other than income tax	9	6	—	15
Operating income	$132	$ 41	$ (2)	$ 171
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

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 revenues	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

Table of Contents

Nine Months Ended September 30, 2018	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,411	$ 442	$ (356)	$ 1,497
Service revenues	599	395	(10)	984
Total Revenues	2,010	837	(366)	2,481
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,262	438	(365)	1,335
Gross margin [1]	748	399	(1)	1,146
Operation and maintenance, General and administrative	230	141	(1)	370
Depreciation and amortization	191	101	—	292
Taxes other than income tax	29	19	—	48
Operating income	$298	$ 138	$ —	$ 436
Equity in earnings of equity method affiliate	$—	$ 20	$ —	$ 20

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 revenues	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

(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.

Table of Contents

	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Operating Data:				
Gathered volumes—TBtu	424	325	1,212	922
Gathered volumes—TBtu/d	4.61	3.52	4.44	3.38
Natural gas processed volumes—TBtu (1)	230	174	641	516
Natural gas processed volumes—TBtu/d (1)	2.50	1.90	2.35	1.89
NGLs produced—MBbl/d (1)(2)	142.65	84.48	127.92	84.02
NGLs sold—MBbl/d (1)(2)(3)	146.29	86.83	130.18	84.10
Condensate sold—MBbl/d	4.25	3.75	5.97	4.75
Crude Oil—Gathered volumes—MBbl/d	31.87	28.87	29.11	24.44
Transported volumes—TBtu	480	445	1,463	1,383
Transported volumes—TBtu/d	5.22	4.83	5.35	5.05
Interstate firm contracted capacity—Bcf/d	5.76	5.62	5.84	6.35
Intrastate average deliveries—TBtu/d	1.84	1.90	1.90	1.86

(1) Includes volumes under third party processing arrangements.
(2) Excludes condensate.
(3) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Anadarko				
Gathered volumes—TBtu/d	2.31	1.72	2.16	1.75
Natural gas processed volumes—TBtu/d (1)	2.08	1.57	1.94	1.56
NGLs produced—MBbl/d (1)(2)	124.80	70.85	111.74	70.99
Arkoma				
Gathered volumes—TBtu/d	0.56	0.53	0.55	0.55
Natural gas processed volumes—TBtu/d (1)	0.10	0.09	0.10	0.09
NGLs produced—MBbl/d (1)(2)	7.04	4.85	6.54	4.77
Ark-La-Tex				
Gathered volumes—TBtu/d	1.74	1.27	1.73	1.08
Natural gas processed volumes—TBtu/d	0.32	0.24	0.31	0.24
NGLs produced—MBbl/d (2)	10.16	8.78	9.64	8.26

(1) Includes volumes under third party processing arrangements.
(2) Excludes condensate.

Gathering and Processing

Three months ended September 30, 2018 compared to three months ended September 30, 2017. Our gathering and processing segment reported operating income of $132 million for the three months ended September 30, 2018 compared to operating income of $99 million for the three months ended September 30, 2017. The difference of $33 million in operating income between periods was primarily due to a $51 million increase in gross margin. This was partially offset by a $10 million increase in depreciation and amortization, and an $8 million increase in operation and maintenance and general and administrative expenses during the three months ended September 30, 2018.

Table of Contents

Our gathering and processing segment revenues increased $236 million. The increase was primarily due to the following:

Product Sales:

- revenues from NGL sales increased $201 million resulting from higher average NGL prices, higher processed volumes and increased recoveries of ethane in the Anadarko and Ark-La-Tex Basins, inclusive of an $7 million decrease due to the implementation of ASC 606.

This increase was partially offset by:

- revenues from natural gas sales decreased $23 million primarily due to a $29 million decrease related to the implementation of ASC 606 and a $6 million increase due to higher sales volumes, and
- changes in the fair value of natural gas, condensate and NGL derivatives decreased $7 million.

Service Revenues:

- processing service revenues increased $45 million resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex Basins, inclusive of a $33 million increase due to the implementation of ASC 606,
- natural gas gathering revenues increased $18 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of an $10 million decrease due to the implementation of ASC 606, and
- crude oil and water gathering revenues increased $2 million due to an increase in gathered volumes partially offset by a reduction in average rates.

Our gathering and processing segment gross margin increased $51 million. The increase was primarily due to the following:

- processing service fees increased $45 million from higher processed volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $33 million increase due to the implementation of ASC 606,
- natural gas gathering fees increased $18 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $10 million decrease due to the implementation of ASC 606, and
- crude oil and water gathering fees increased $2 million due to an increase in gathered volumes partially offset by a reduction in average rates.

These increases were partially offset by:

- a decrease in the changes in the fair value of natural gas, condensate and NGL derivatives of $7 million,
- revenues from natural gas sales less the cost of natural gas decreased $6 million primarily due to a $14 million change in imbalance volumes owed customers, a $4 million increase in fuel costs and a $3 million increase in third party processing fees, partially offset by a $15 million increase due to higher sales volumes, which is inclusive of an $8 million increase due to the implementation of ASC 606, and
- revenues from NGL sales less the cost of NGLs decreased $1 million, inclusive of a $31 million decrease due to the implementation of ASC 606, partially offset by higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $8 million. The increase was primarily due to a $4 million increase in expenses related to maintenance on treating plants as a result of increased activity on our Ark-La-Tex assets, a $2 million increase in compressor rental expenses due to increased rental units, a $2 million increase in materials and supplies and contract services expense as a result of additional assets in service and a $2 million increase in payroll-related costs. These increases were partially offset by a $1 million decrease due to an increase in capitalized overhead costs as a result of an increase in capital projects in the third quarter of 2018.

Our gathering and processing segment depreciation and amortization increased $10 million primarily due to the amortization of customer intangibles acquired as part of the Align Midstream, LLC acquisition in the fourth quarter of 2017.

Nine months ended September 30, 2018 compared to nine months ended September 30, 2017. Our gathering and processing segment reported operating income of $298 million for the nine months ended September 30, 2018 compared to operating income of $241 million for the nine months ended September 30, 2017. The difference of $57 million in operating income between periods was primarily due to a $98 million increase in gross margin. This was partially offset by a $15 million increase in operation and maintenance and general and administrative expenses, a $24 million increase in depreciation and amortization and a $2 million increase in taxes other than income tax during the nine months ended September 30, 2018.

Table of Contents

Our gathering and processing segment revenues increased $497 million. The increase was primarily due to the following:

Product Sales:

- revenues from NGL sales increased $433 million resulting from higher average NGL prices, higher processed volumes and increased recoveries of ethane in the Anadarko and Ark-La-Tex Basins, inclusive of a $19 million decrease due to the implementation of ASC 606.

These increases were partially offset by:

- revenues from natural gas sales decreased $36 million due to a $51 million decrease related to the implementation of ASC 606, a decrease of $3 million in the imbalance position, partially offset by a $19 million increase due to higher sales volumes, and
- changes in the fair value of natural gas, condensate and NGL derivatives decreased $30 million.

Service Revenues:

- processing service revenues increased $100 million resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex Basins, inclusive of a $57 million increase due to the implementation of ASC 606,
- natural gas gathering revenues increased $25 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $33 million decrease due to the implementation of ASC 606, and
- crude oil and water gathering revenues increased $5 million due to an increase in gathered volumes partially offset by a reduction in average rates.

Our gathering and processing segment gross margin increased $98 million. The increase was primarily due to the following:

- processing service fees increased $100 million due to higher processed volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $57 million increase due to the implementation of ASC 606,
- natural gas gathering fees increased $25 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $33 million decrease due to the implementation of ASC 606,
- crude oil and water gathering fees increased $5 million due to an increase in gathered volumes partially offset by a reduction in average rates, and
- revenues from natural gas sales less the cost of natural gas remained flat primarily due to an $6 million increase due to higher sales volumes, a $25 million change in imbalance volumes owed customers and a $10 million increase in fuel costs, inclusive of a $31 million increase due to the implementation of ASC 606.

These increases were partially offset by:

- changes in the fair value of natural gas, condensate and NGL derivatives decreased $30 million, and
- revenues from NGL sales less the cost of NGLs decreased $2 million inclusive of a $55 million decrease due to the implementation of ASC 606, partially offset by higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $15 million. The increase was primarily due to a $9 million increase in expenses related to maintenance on treating plants as a result of increased activity on our Ark-La-Tex assets, a $7 million increase in materials and supplies and contract services expense as a result of additional assets in service, a $6 million increase in compressor rental expenses due to increased rental units, and a $6 million increase in payroll-related costs. These were partially offset by a $5 million decrease due to a loss on the disposal of assets in the second quarter of 2017, for which there were no comparable items in 2018, a $5 million decrease due to an increase in capitalized overhead costs as a result of an increase in projects in 2018 and a $2 million change in the allowance for doubtful accounts due to the collection of accounts receivable in the nine months ended September 30, 2018 that were previously included in the allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization increased $24 million primarily due to the amortization of customer intangibles acquired as part of the Align Midstream, LLC acquisition in the fourth quarter of 2017.

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

Transportation and Storage

Three months ended September 30, 2018 compared to three months ended September 30, 2017. Our transportation and storage segment reported operating income of $41 million for the three months ended September 30, 2018 compared to operating

Table of Contents

income of $38 million for the three months ended September 30, 2017. The difference of $3 million in operating income between periods was primarily due to a $6 million increase in gross margin and a $3 million increase in operation and maintenance and general and administrative expenses.

Our transportation and storage segment revenues increased $4 million. The increase was primarily due to the following:

Product Sales:

- revenues from natural gas sales increased $4 million, inclusive of an increase of $5 million primarily due to higher sales volumes offset by a $1 million decrease due to the implementation of ASC 606.

These increases were partially offset by:

- changes in the fair value of natural gas derivatives decreased $3 million.

Service Revenues:

- volume-dependent transportation revenues increased $2 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates and
- other firm transportation and storage services increased $1 million due to new intrastate transportation contracts.

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

- system management activities increased $6 million,
- volume-dependent transportation increased $2 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates, and
- other firm transportation and storage services increased $1 million due to new intrastate transportation contracts.

These increases were partially offset by:

- changes in the fair value of natural gas derivatives decreased $3 million.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $3 million. The increase was primarily due to a $3 million increase in materials and supplies and contract services expense and a $1 million increase in payroll-related costs. These increases were partially offset by a $1 million decrease due to increased capitalized overhead costs.

Nine months ended September 30, 2018 compared to nine months ended September 30, 2017. Our transportation and storage segment reported operating income of $138 million for the nine months ended September 30, 2018 compared to operating income of $158 million for the nine months ended September 30, 2017. The difference of $20 million in operating income between periods was primarily due to a $14 million decrease in gross margin, a $6 million increase in operation and maintenance and general and administrative expenses, and a $1 million increase in depreciation and amortization, partially offset by a $1 million decrease in taxes other than income for the nine months ended September 30, 2018.

Our transportation and storage segment revenues increased $3 million. The increase was primarily due to the following:

Product Sales:

- revenues from natural gas sales increased $29 million primarily due to higher sales volumes, inclusive of a $3 million decrease due to the implementation of ASC 606, and
- revenues from NGL sales increased $1 million due to an increase in prices.

These increases were partially offset by:

- changes in the fair value of natural gas derivatives decreased $27 million.

Service Revenues:

- volume-dependent transportation revenues increased $11 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates and

- other firm transportation and storage services increased $6 million due to new intrastate transportation contracts.

These increases were partially offset by:

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

Table of Contents

Our transportation and storage segment gross margin decreased $14 million. The decrease was primarily due to the following:

- changes in the fair value of natural gas derivatives decreased $27 million, and
- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $17 million due to contract expirations during the second quarter of 2017.

These decreases were partially offset by:

- system management activities increased $13 million,
- volume-dependent transportation increased $11 million primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates, and
- other firm transportation and storage services increased $6 million due to new intrastate transportation contracts.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $6 million. The increase was primarily due to a $5 million increase in materials and supplies and contract services expenses, a $3 million increase in payroll-related costs, and a $1 million increase in one-time reimbursements associated with an unplanned pipeline outage. These increases were partially offset by a $3 million decrease due to increased capitalized overhead costs.

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

Our transportation and storage segment taxes other than income tax decreased $1 million driven by a decrease in accrued ad valorem taxes due to a decrease in operating income.

Condensed Consolidated Interim Information

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Operating Income	$171	$137	$436	$399
Other Income (Expense):				
Interest expense	(40)	(31)	(109)	(89)
Equity in earnings of equity method affiliate	7	7	20	21
Other, net	1	—	1	—
Total Other Expense	(32)	(24)	(88)	(68)
Income Before Income Taxes	139	113	348	331
Income tax expense	—	—	—	2
Net Income	$139	$113	$348	$329
Less: Net income attributable to noncontrolling interest	1	—	1	1
Net Income Attributable to Limited Partners	$138	$113	$347	$328
Less: Series A Preferred Unit distributions	9	9	27	27
Net Income Attributable to Common and Subordinated Units	$129	$104	$320	$301

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

Net Income attributable to limited partners. We reported net income attributable to limited partners of $138 million in the three months ended September 30, 2018 compared to $113 million in the three months ended September 30, 2017. The increase of $25 million was primarily attributable to an increase in operating income of $34 million partially offset by an increase in interest expense of $9 million in the three months ended September 30, 2018.

Interest Expense. Interest expense increased $9 million primarily due to an increase in the amount of debt outstanding as well as higher interest rates on the Partnership's outstanding debt as a result of a long-term debt issuance in May 2018 that resulted in the repayment of amounts outstanding under the Partnership's 2015 Term Loan Agreement, as well as amounts outstanding under our commercial paper program.

Table of Contents

Nine Months Ended September 30, 2018 compared to Nine Months Ended September 30, 2017

Net Income attributable to limited partners. We reported net income attributable to limited partners of $347 million in the nine months ended September 30, 2018 compared to net income attributable to limited partners of $328 million in the nine months ended September 30, 2017. The increase in net income attributable to limited partners of $19 million was primarily attributable to an increase in operating income of $37 million partially offset by an increase in interest expense of $20 million in the nine months ended September 30, 2018.

Interest Expense. Interest expense increased $20 million primarily due to an increase in the amount of debt outstanding as well as higher interest rates on the Partnership's outstanding debt as a result of a long-term debt issuance in May 2018 that resulted in the repayment of amounts outstanding under the Partnership's 2015 Term Loan Agreement, as well as amounts outstanding under our commercial paper program.

Reconciliations of Non-GAAP Financial Measures

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

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

Table of Contents

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(In millions)			
Reconciliation of Gross margin to Total Revenues:				
Consolidated				
Product sales	$553	$396	$1,497	$1,136
Service revenues	375	309	984	861
Total Revenues	928	705	2,481	1,997
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	516	349	1,335	936
Gross margin	$412	$356	$1,146	$1,061
Reportable Segments				
Gathering and Processing				
Product sales	$528	$357	$1,411	$1,044
Service revenues	250	185	599	469
Total Revenues	778	542	2,010	1,513
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	493	308	1,262	863
Gross margin	$285	$234	$748	$650
Transportation and Storage				
Product sales	$153	$152	$442	$439
Service revenues	128	125	395	395
Total Revenues	281	277	837	834
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	152	154	438	421
Gross margin	$129	$123	$399	$413

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

	Fee-Based [1]			
	Demand	Volume-Dependent	Commodity-Based [1]	Total
Nine Months Ended September 30, 2018				
Gathering and Processing Segment	25 %	52 %	23 %	100 %
Transportation and Storage Segment	87 %	12 %	1 %	100 %
Partnership Weighted Average	47 %	37 %	16 %	100 %

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

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions, except Distribution coverage ratio)			
Reconciliation of Adjusted EBITDA and DCF to net income attributable to limited partners and calculation of Distribution coverage ratio:				
Net income attributable to limited partners	$138	$113	$347	$328
Depreciation and amortization expense	100	90	292	267
Interest expense, net of interest income	40	31	109	89
Income tax expense	—	—	—	2
Distributions received from equity method affiliate in excess of equity earnings	3	4	11	9
Non-cash equity-based compensation	4	4	12	12
Change in fair value of derivatives	16	6	28	(29)
Other non-cash losses (1)	—	2	4	8
Adjusted EBITDA	$301	$250	$803	$686
Series A Preferred Unit distributions (2)	(9)	(9)	(27)	(27)
Distributions for phantom and performance units (3)	(1)	(1)	(5)	(2)
Adjusted interest expense (4)	(41)	(31)	(114)	(90)
Maintenance capital expenditures	(30)	(22)	(70)	(53)
DCF	$220	$187	$587	$514
Distributions related to common and subordinated unitholders (5)	$138	$138	$414	$413
Distribution coverage ratio	1.60	1.36	1.42	1.25

(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, 2018 and 2017. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made.

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

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

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

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:				
Net cash provided by operating activities	$233	$174	$638	$556
Interest expense, net of interest income	40	31	109	89
Net income attributable to noncontrolling interest	(1)	—	(1)	(1)
Other non-cash items [1]	—	—	4	2
Proceeds from insurance	—	—	1	—
Changes in operating working capital which (provided) used cash:				
Accounts receivable	46	100	58	72
Accounts payable	—	(30)	19	16
Other, including changes in noncurrent assets and liabilities	(36)	(35)	(64)	(28)
Return of investment in equity method affiliate	3	4	11	9
Change in fair value of derivatives	16	6	28	(29)
Adjusted EBITDA	$301	$250	$803	$686

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In millions)			
Reconciliation of Adjusted interest expense to Interest expense:				
Interest Expense	$40	$31	$109	$89
Amortization of premium on long-term debt	1	1	4	4
Capitalized interest on expansion capital	—	—	4	—
Amortization of debt expense and discount	—	(1)	(3)	(3)
Adjusted interest expense	$41	$31	$114	$90

Liquidity and Capital Resources

The Partnership’s principal liquidity requirements are to finance its operations, fund capital expenditures and acquisitions, make cash distributions and satisfy any indebtedness obligations. We expect that our liquidity and capital resource needs will be met by cash on hand, operating cash flow, proceeds from commercial paper issuances, borrowings under our revolving credit facility, debt issuances and the issuance of equity. However, issuances of equity or debt in the capital markets and additional credit facilities may not be available to us on acceptable terms. Access to funds obtained through the equity or debt capital markets, particularly in the energy sector, has been constrained by a variety of market factors that have hindered the ability of energy companies to raise new capital or obtain financing at acceptable terms. Factors that contribute to our ability to raise capital through these channels depend on our financial condition, credit ratings and market conditions. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. See Part II, Item 1A. “Risk Factors” for further discussion.

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, the level and timing of spending for maintenance and expansion activity, and the timing of debt maturities. As of September 30, 2018, we had a working capital deficit of $922 million. The deficit is primarily due to the classification of $500 million of 2019 Notes

Table of Contents

debt as Current portion of long-term debt as of September 30, 2018 as well as $413 million of commercial paper outstanding as of September 30, 2018. We utilize our commercial paper program and Revolving Credit Facility to manage the timing of cash flows and fund short-term working capital deficits.

Cash Flows

The following tables reflect cash flows for the applicable periods:

	Nine Months Ended September 30,	
	2018	2017
	(In millions)	
Net cash provided by operating activities	$638	$556
Net cash used in investing activities	$(531)	$(240)
Net cash used in financing activities	$(104)	$(317)

Operating Activities

The increase of $82 million, or 15%, in net cash provided by operating activities for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 was primarily driven by an increase of $46 million in the timing of cash receipts and disbursements and changes in other working capital assets and liabilities, an increase in net income of $19 million and an increase of $17 million in other non-cash items.

Investing Activities

The increase of $291 million, or 121%, in net cash used in investing activities for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 was primarily due to higher capital expenditures of $301 million partially offset by an increase in proceeds from sale of asset of $7 million due to the 2018 sale of a cryogenic processing plant, previously included in assets held for sale, and an increase in return of investment in equity method affiliate of $2 million.

Financing Activities

Net cash used in financing activities decreased $213 million, or 67%, for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. Our primary financing activities consist of the following:

	Nine Months Ended September 30,	
	2018	2017
	(In millions)	
Repayment of Term Loan Agreement	$(450)	$ —
Increase in short-term debt	8	—
Proceeds from long-term debt, net of issuance costs	787	691
Net repayments from Revolving Credit Facility	—	(563)
Proceeds from issuance of common units, net of issuance costs	2	—
Distributions	(442)	(443)
Cash paid for employee equity-based compensation	(9)	(2)

Please see Note 8, "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, 2018, our sources of liquidity included:
- cash on hand;
- cash generated from operations;
- proceeds from commercial paper issuances;

Table of Contents

- borrowings under our Revolving Credit Facility; and
- capital raised through debt and equity markets.

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement, pursuant to which the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. During the three and nine months ended September 30, 2018, the partnership issued 140,920 common units, which generated proceeds of approximately $2 million (net of approximately $25,000 of commissions). During the nine months ended September 30, 2017, the Partnership issued 18,500 common units, which generated proceeds of approximately $303,000 (net of $3,000 of commissions). The proceeds were used for general partnership purposes. As of September 30, 2018, $197 million of common units remained available for issuance through the ATM Program.

Distribution Reinvestment Plan

In June 2016, the Partnership implemented a Distribution Reinvestment Plan, which offers owners of our common units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common units. The Partnership reserved the right to suspend, modify or terminate the DRIP at any time. The Partnership had minimal participation in the DRIP during the three and nine months ended September 30, 2018. On July 31, 2018, the Partnership suspended the DRIP.

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 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, issuances of commercial paper, borrowings under our Revolving Credit Facility, or other issuances of debt or equity in the capital markets. Issuances of equity or debt in the capital markets may not, however, be available to us on acceptable terms.

Distributions

On November 6, 2018, 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, 2018. The distributions will be paid November 29, 2018 to unitholders of record as of the close of business on November 16, 2018. 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, 2018 to unitholders of record as of the close of business on November 6, 2018.

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.

Table of Contents

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 commodities 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.

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. The accounting policies and estimates used in preparing our interim Condensed Consolidated Financial Statements for the three months ended September 30, 2018 are the same as those described in our Annual Report.

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 9 of the Notes to the Unaudited Condensed Consolidated Financial Statements.

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, 2018 is directly exposed to changes in commodity prices, excluding the impact of hedges and contractual floors related to commodity prices in certain agreements. Since September 30, 2018, we have entered into additional derivative contracts to further manage our exposure to commodity price risk for the three months ending December 31, 2018.

Commodity price risk is estimated as the potential loss in value resulting from a hypothetical 10% decline in prices over the next three months on a sensitivity analysis, a 10% decrease in prices from forecasted levels would decrease net income by approximately \$5 million for natural gas and ethane and \$4 million for NGLs (other than ethane) and condensate, excluding the impact of hedges, for the remaining three months ending December 31, 2018.

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 $413 million outstanding borrowings under commercial paper as of September 30, 2018, and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $4 million.

Table of Contents

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, 2018. Based on such evaluation, our management has concluded that, as of September 30, 2018, 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 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

There were no changes in our internal controls over financial reporting during the quarter ended September 30, 2018, 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 13—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 and March 31 Quarterly Report. No other material changes to such risk factors have occurred during the three and nine months ended September 30, 2018.

Item 6. Exhibits

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.

Table of Contents

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	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Registrant's Form 8-K filed November 15, 2017	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 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
4.5	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
4.6	Third Supplemental Indenture, dated as of May 10, 2018, by and among Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Registrant's Form 8-K filed May 10, 2018	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.

Table of Contents

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 7, 2018	By:	/s/ Tom Levescy Tom Levescy Senior Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)