Enable Midstream Partners, LP
Form 10-Q
May 04, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES AND EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____
Commission File No. 1-36413

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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 April 15, 2016, there were 214,467,409 common units and 207,855,430 subordinated units outstanding.

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GLOSSARY

Adjusted EBITDA.	A non-GAAP measure calculated as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results.
Annual Report.	Annual Report on Form 10-K for the year ended December 31, 2015.
ASU.	Accounting Standards Update.
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, other than Enable Midstream Partners, LP for periods prior to formation of the Partnership on May 1, 2013.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
Enable Midstream Services.	Enable Midstream Services, LLC, a wholly owned subsidiary of Enable Midstream Partners, LP.
Enogex.	Enogex LLC, a Delaware limited liability company.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
Exchange Act.	Securities Exchange Act of 1934, as amended.
FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Generally accepted accounting principles in the United States.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.
General partner.	Enable GP, LLC, a Delaware limited liability company, the general partner of Enable Midstream Partners, LP.
Gross margin.	A non-GAAP measure calculated as revenues minus cost of natural gas and natural gas liquids, excluding depreciation and amortization.
LIBOR.	London Interbank Offered Rate.
MBbl/d.	Thousand barrels per day.
MFA.	Master Formation Agreement dated as of March 14, 2013.
MMcf.	Million cubic feet of natural gas.
MMcf/d.	Million cubic feet per day.
NGLs.	

	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
Offering.	Initial public offering of Enable Midstream Partners, LP.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries.
Partnership.	Enable Midstream Partners, LP, and its subsidiaries.

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Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of February 18, 2016.
Purchase Agreement.	Purchase Agreement, dated January 28, 2016, by and between the Partnership and CenterPoint Energy, Inc. for the sale by the Partnership and purchase by CenterPoint Energy, Inc. of Series A Preferred Units.
Revolving Credit Facility.	$1.75 billion senior unsecured revolving credit facility.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
Series A Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% interest, that operates an approximately 290-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
WTI.	West Texas Intermediate.
2015 Term Loan Agreement.	$450 million unsecured term loan agreement.
2019 Notes.	$500 million 2.400% senior notes due 2019.
2024 Notes.	$600 million 3.900% senior notes due 2024.
2044 Notes.	$550 million 5.000% senior notes due 2044.

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FORWARD-LOOKING STATEMENTS

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

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report and in our Annual Report on Form 10-K for the year ended December 31, 2015 (Annual Report). Those risk factors and other factors noted throughout this report and in our Annual Report could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

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

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

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three Months Ended March 31,	
	2016	2015
	(In millions, except per unit data)	
Revenues (including revenues from affiliates (Note 11)):		
Product sales	$245	$351
Service revenue	264	265
Total Revenues	509	616
Cost and Expenses (including expenses from affiliates (Note 11)):		
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	195	292
Operation and maintenance	95	104
General and Administrative	20	26
Depreciation and amortization	81	73
Taxes other than income taxes	15	17
Total Cost and Expenses	406	512
Operating Income	103	104
Other Income (Expense):		
Interest expense (including expenses from affiliates (Note 11))	(23)	(20)
Equity in earnings of equity method affiliates	7	7
Other, net	—	1
Total Other Income (Expense)	(16)	(12)
Income Before Income Taxes	87	92
Income tax expense	1	1
Net Income	$86	$91
Less: Net income attributable to noncontrolling interest	—	—
Less: Series A Preferred Unit distributions (Note 4)	—	—
Net Income attributable to common and subordinated units (Note 3)	$86	$91
Basic earnings per unit (Note 3)		
Common units	$0.21	$0.22
Subordinated units	$0.20	$0.21
Diluted earnings per unit (Note 3)		
Common units	$0.19	$0.22
Subordinated units	$0.20	$0.21
Basic weighted average number of outstanding (Note 3)		
Common units	214	214
Subordinated units	208	208

Diluted weighted average number of outstanding (Note 3)		
Common units	235	214
Subordinated units	208	208

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Net income	$ 86	$ 91
Comprehensive income	86	91
Less: Comprehensive income attributable to noncontrolling interest	—	—
Comprehensive income attributable to Enable Midstream Partners, LP	$ 86	$ 91

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

	March 31, 2016	December 31, 2015
	(In millions)	
Current Assets:		
Cash and cash equivalents	$38	$ 4
Accounts receivable	226	245
Accounts receivable—affiliated companies	16	21
Inventory	45	53
Gas imbalances	20	23
Other current assets	35	35
Total current assets	380	381
Property, Plant and Equipment:		
Property, plant and equipment	11,395	11,293
Less accumulated depreciation and amortization	1,219	1,162
Property, plant and equipment, net	10,176	10,131
Other Assets:		
Intangible assets, net	327	333
Investment in equity method affiliates	331	344
Other	35	37
Total other assets	693	714
Total Assets	$11,249	$ 11,226
Current Liabilities:		
Accounts payable	$153	$ 248
Accounts payable—affiliated companies	6	9
Short-term debt	—	236
Taxes accrued	29	30
Gas imbalances	7	25
Other	85	67
Total current liabilities	280	615
Other Liabilities:		
Accumulated deferred income taxes, net	8	8
Notes payable—affiliated companies	—	363
Regulatory liabilities	18	18
Other	22	20
Total other liabilities	48	409
Long-Term Debt	3,074	2,671
Commitments and Contingencies (Note 12)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at March 31, 2016 and 0 issued and outstanding at December 31, 2015)	362	—
Common units (214,467,409 issued and outstanding at March 31, 2016 and 214,541,422 issued and outstanding at December 31, 2015, respectively)	3,692	3,714
Subordinated units (207,855,430 issued and outstanding at March 31, 2016 and December 31, 2015, respectively)	3,781	3,805
Noncontrolling interest	12	12
Total Partners' Equity	7,847	7,531

Total Liabilities and Partners' Equity	$11,249	$ 11,226

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$86	$91
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	81	73
Loss on sale/retirement of assets	1	—
Equity in earnings of equity method affiliates, net of distributions	—	5
Equity based compensation	2	3
Amortization of debt costs and discount (premium)	(1)	(1)
Changes in other assets and liabilities:		
Accounts receivable, net	19	2
Accounts receivable—affiliated companies	5	(2)
Inventory	8	13
Gas imbalance assets	3	8
Other current assets	—	6
Other assets	1	(2)
Accounts payable	(84)	18
Accounts payable—affiliated companies	(3)	(21)
Gas imbalance liabilities	(18)	(5)
Other current liabilities	15	2
Other liabilities	2	(2)
Net cash provided by operating activities	117	188
Cash Flows from Investing Activities:		
Capital expenditures	(130)	(239)
Investment in equity method affiliates	—	(6)
Return of investment in equity method affiliates	13	—
Net cash used in investing activities	(117)	(245)
Cash Flows from Financing Activities:		
Proceeds from revolving credit facility	495	—
Repayment of revolving credit facility	(90)	—
Increase (decrease) in short-term debt	(236)	183
Repayment of notes payable—affiliated companies	(363)	—
Proceeds from issuance of Series A Preferred Units, net of issuance costs	362	—
Distributions	(134)	(130)
Net cash provided by financing activities	34	53
Net Increase (Decrease) in Cash and Cash Equivalents	34	(4)
Cash and Cash Equivalents at Beginning of Period	4	12
Cash and Cash Equivalents at End of Period	$38	$8

See Notes to the Unaudited Condensed Consolidated Financial Statements

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

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
	(In millions)							
Balance as of December 31, 2014	—	$—	214	$4,353	208	$4,439	$ 31	$8,823
Net income	—	—	—	48	—	43	—	91
Distributions	—	—	—	(66)	—	(64)	—	$(130)
Equity based compensation	—	—	—	3	—	—	—	$3
Balance as of March 31, 2015	—	$—	214	$4,338	208	$4,418	$ 31	$8,787
Balance as of December 31, 2015	—	$—	214	$3,714	208	$3,805	$ 12	$7,531
Net income	—	—	—	44	—	42	—	86
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Distributions	—	—	—	(68)	—	(66)	—	(134)
Equity based compensation	—	—	—	2	—	—	$ —	2
Balance as of March 31, 2016	15	$362	214	$3,692	208	$3,781	$ 12	$7,847

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

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership), a Delaware limited partnership, is a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. The Partnership’s assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers. The natural gas gathering and processing assets are located in five states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes a crude oil gathering business in the Bakken Shale formation, principally located in the Williston basin. The natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50% of the management rights of Enable GP. Enable GP was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. Enable GP is governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy, along with the independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. Based on the 50/50 management ownership, with neither company having control, CenterPoint Energy and OGE Energy do not consolidate their interests in the Partnership. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP. As of March 31, 2016, CenterPoint Energy held approximately 55.4% of the common and subordinated units in the Partnership, or 94,151,707 common units and 139,704,916 subordinated units, and OGE Energy held approximately 26.3% of the common and subordinated units in the Partnership, or 42,832,291 common units and 68,150,514 subordinated units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 4 for further information related to the Series A Preferred Units.

For the period from December 31, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership. As of March 31, 2016, the Partnership owned a 50% interest in SESH. See Note 6 for further discussion of SESH.

Basis of Presentation

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

These condensed consolidated financial statements and the related financial statement disclosures reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. Amounts reported in the Partnership’s Condensed Consolidated

Statements of Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c) timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests.

For a description of the Partnership’s reportable segments, see Note 14.

Use of Estimates

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

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Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable at least quarterly, as well as the bad debt write-offs experienced in the past. Based on this review, a $3 million allowance for doubtful accounts was recognized as of March 31, 2016. There was no allowance for doubtful accounts as of December 31, 2015.

Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On February 18, 2016, in connection with the closing of the private placement of 14,520,000 Series A Preferred Units and pursuant to the Purchase Agreement, the General partner adopted the Third Amended and Restated Agreement of Limited Partnership (the Partnership Agreement) which, among other things, authorized and established the terms of the Series A Preferred Units and the other series of preferred units that are issuable upon conversion of the Series A Preferred Units. For further information related to the issuance of the Series A Preferred Units, see Note 4.

(2) New Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers,” which supersedes the revenue recognition requirements in “Revenue Recognition (Topic 605),” and requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. ASU 2014-09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted.

In August 2015, the FASB issued ASU No. 2015-14, “Revenue from Contracts with Customers (Topic 606)—Deferral of the Effective Date,” which deferred the effective date of ASU 2014-09 by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Condensed Consolidated Financial Statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-08, “Revenue from Contracts with Customers (Topic 606)-Principal versus Agent Considerations (Reporting Revenue Gross versus Net)”. ASU No. 2016-08 requires an entity to determine whether the nature of its promise is to provide the specified good or service itself (i.e., the entity is a principal) or to arrange for that good or service to be provided by the other party (i.e., the entity is an agent) when another party is involved in providing goods or services to a customer. Additionally, the amendments in this ASU require an entity that is a principal to recognize revenue in the gross amount of consideration to which it expects to be entitled in exchange for the specified good or service transferred to the customer, and require an entity that is an agent to recognize revenue in the amount of any fee or commission to which it expects to be entitled in exchange for arranging for the specified good or service to be provided by the other party. ASU 2016-08 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Condensed Consolidated Financial Statements and related disclosures.

In April 2016, the FASB issued ASU No. 2016-10, “Revenue from Contracts with Customers (Topic 606)-Identifying Performance Obligations and Licensing”. The amendments in ASU No. 2016-10 impact entities with transactions that include contracts with customers to transfer goods or services (that are an output of the entity's ordinary activities) in exchange for consideration, and they require entities to recognize revenue by following certain steps, including (1) identifying the contract(s) with a customer; (2) identifying the performance obligations in a contract; (3) determining the transaction price; (4) allocating the transaction price to the performance obligations in the contract; and (5) recognizing revenue when, or as, the entity satisfies a performance obligation. Notably, ASU No. 2016-10 does not impact the core revenue recognition principles set forth in Topic 606, but rather clarifies the identification of performance obligations and the licensing implementation guidance, while retaining the related principles for those areas. ASU 2016-10 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Condensed Consolidated Financial Statements and related disclosures.

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Consolidation

In February 2015, the FASB issued ASU No. 2015-02, "Consolidation," to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. The Partnership adopted the amendment in the first quarter of 2016, which resulted in no impact to our Condensed Consolidated Financial Statements and related disclosures.

Presentation of Debt Issuance Costs

In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs." This standard amends existing guidance to require the presentation of debt issuance costs in the balance sheet as a deduction from the carrying amount of the related debt liability instead of a deferred charge. The Partnership adopted the amendment in the first quarter of 2016 on a retrospective basis in order to conform the presentation of debt issuance costs on the Condensed Consolidated Balance Sheets. At each of March 31, 2016 and December 31, 2015, the Partnership had unamortized debt expense of $12 million classified as a reduction of Long-Term Debt in the Condensed Consolidated Balance Sheets. Unamortized debt expense related to the Revolving Credit Facility of $5 million and $6 million as of March 31, 2016 and December 31, 2015, respectively, is classified as Other Assets in the Condensed Consolidated Balance Sheets.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU No. 2015-17, "Income Taxes—Balance Sheet Classification of Deferred Taxes." This ASU eliminates the requirement to present deferred tax liabilities and assets as current and non-current in a classified balance sheet. Instead, all deferred tax assets and liabilities will be classified as non-current. ASU 2015-17 is effective for all interim and annual periods beginning after December 16, 2016 and early application is permitted. The amendments in this update may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. The Partnership adopted the amendment in the first quarter of 2016, which resulted in no impact to our Condensed Consolidated Financial Statements and related disclosures.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases". The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Partnership expects to adopt the amendments in the first quarter of 2019 and is currently evaluating the impacts of the amendments to our Condensed Consolidated Financial Statements and accounting practices for leases.

Share-Based Compensation

In March 2016, the FASB issued ASU No. 2016-09, "Compensation—Stock Compensation (Topic 718)." This standard makes several modifications to Topic 718 related to the accounting for forfeitures, employer tax withholding on share-based compensation and the financial statement presentation of excess tax benefits or deficiencies. ASU

2016-09 also clarifies the statement of cash flows presentation for certain components of share-based awards. The standard is effective for interim and annual reporting periods beginning after December 15, 2016, although early adoption is permitted. The Partnership is currently assessing how the adoption of this standard will impact our Condensed Consolidated Financial Statements and related disclosures.

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(3) Earnings Per Limited Partner Unit

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

	Three Months Ended March 31,	
	2016	2015
	(In millions, except per unit data)	
Net income	$86	$91
Net income attributable to noncontrolling interest	—	—
Series A Preferred Unit distribution	—	—
General partner interest in net income	—	—
Net income available to common and subordinated unitholders	$86	$91
Net income allocable to common units	$44	$48
Net income allocable to subordinated units	42	43
Net income available to common and subordinated unitholders	$86	$91
Net income allocable to common units	$44	$48
Series A Preferred Unit Distribution	—	—
Diluted net income allocable to common units	44	48
Diluted net income allocable to subordinated units	42	43
Total	$86	$91
Basic weighted average number of outstanding		
Common units	214	214
Subordinated units	208	208
Total	422	422
Basic earnings per unit		
Common units	$0.21	$0.22
Subordinated units	$0.20	$0.21
Basic weighted average number of outstanding common units	214	214
Dilutive effect of Series A Preferred Units	21	—
Diluted weighted average number of outstanding common units	235	214
Diluted weighted average number of outstanding subordinated units	208	208
Total	443	422
Diluted earnings per unit		
Common units	$0.19	$0.22
Subordinated units	$0.20	$0.21

There was no dilutive effect of equity based compensation during the three months ended March 31, 2016 and 2015.

(4) Partners’ Equity

The Partnership Agreement requires that, within 45 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders during 2015 and 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
March 31, 2016 (1)	May 6, 2016	May 13, 2016	$ 0.318	$ 134
December 31, 2015	February 2, 2016	February 12, 2016	$ 0.318	$ 134
September 30, 2015	November 3, 2015	November 13, 2015	$ 0.318	$ 134
June 30, 2015	August 3, 2015	August 13, 2015	$ 0.316	$ 134
March 31, 2015	May 5, 2015	May 15, 2015	$ 0.3125	$ 132

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on April 26, 2016, to be paid on May 13, 2016, to common and subordinated unitholders of record at the close of business on May 6, 2016.

The board of directors of Enable GP declared a $0.2917 per Series A Preferred Unit prorated cash distribution on April 26, 2016, to be paid on May 13, 2016, to Series A Preferred unitholders of record at the close of business on May 6, 2016. The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

General Partner Interest and Incentive Distribution Rights

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

Subordinated Units

Subordinated Unit Ownership

All subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because during the subordination period (as defined in the Partnership Agreement), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.2875 per common unit, which amount is defined in the Partnership Agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units.

Subordination Period

The subordination period began on the closing date of the Offering and will extend until the first business day following which (1) distributions of available cash from operating surplus (as defined in the Partnership Agreement) on each of the outstanding common units and subordinated units equal or exceed $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017 and (2) the adjusted operating surplus for each of the three consecutive, non-overlapping four-quarter periods immediately preceding such date equaled or exceeded the sum of the minimum quarterly distribution on all common units and subordinated units that were outstanding during such periods on a fully diluted weighted average basis. Also, if the Partnership has paid distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150% of the annualized minimum quarterly distribution) and the related distribution on the incentive distribution rights, for any four-consecutive-quarter period ending on or after June 30, 2015, the subordination period will terminate.

Series A Preferred Units

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

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

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

Holders of the Series A Preferred Units receive, on a non-cumulative basis and if and when declared by the General Partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10% on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date and an annual rate of LIBOR plus a spread of 8.5% on the stated liquidation preference thereafter.

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.

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

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. The Partnership recorded no material impairments to long-lived assets in the three months ended March 31, 2016 or 2015. Based upon review of forecasted undiscounted cash flows, none of the asset groups were at risk of failing step one of the impairment test. Further price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions could reduce forecast undiscounted cash flows.

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(6) Investments in Equity Method Affiliates

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.

For the period from December 31, 2014 through June 29, 2015, the Partnership held a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to its remaining 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed a 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership, which had a fair value of $1 million based upon the closing market price of the Partnership's common units. Spectra Energy Partners, LP owns the remaining 50% interest in SESH. 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 our interest in SESH at fair market value. As of March 31, 2016, the Partnership owned a 50% interest in SESH.

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. During the three months ended March 31, 2016 and 2015, the Partnership billed SESH $4 million and $2 million, respectively, associated with these service agreements.

Investment in Equity Method Affiliates:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Balance as of December 31	$344	$348
Equity in earnings of equity method affiliate	7	7
Contributions to equity method affiliate	—	6
Distributions from equity method affiliate[(1)]	(20)	(12)
Balance as of March 31	$331	$349

(1) Distributions from equity method affiliates includes a $7 million and $12 million return on investment and a $13 million and zero return of investment for the three months ended March 31, 2016 and 2015, respectively.

Equity in Earnings of Equity Method Affiliates:

Three Months Ended March 31,	
2016	2015

	(In millions)	
SESH	$ 7	$ 7

Distributions from Equity Method Affiliates:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
SESH	$ 20	$ 12

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Summarized financial information of SESH is presented below:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Income Statements:		
Revenues	$ 29	$ 29
Operating income	19	18
Net income	14	14

(7) Debt

The following table presents the Partnership's outstanding debt as of March 31, 2016 and December 31, 2015.

	March 31, 2016	December 31, 2015
	(In millions)	
Commercial Paper	$ —	$ 236
2015 Term Loan Agreement	450	450
Revolving Credit Facility	715	310
Notes payable — affiliated companies (Note 11)	—	363
2019 Notes	500	500
2024 Notes	600	600
2044 Notes	550	550
EOIT Senior Notes	250	250
Premium (Discount) on long-term debt	21	23
Total debt	3,086	3,282
Less: Short-term debt[(1)]	—	236
Less: Unamortized debt expense	12	12
Less: Notes payable—affiliated companies	—	363
Total long-term debt	$ 3,074	$ 2,671

(1) Short-term debt includes $236 million of commercial paper as of December 31, 2015. There were no commercial paper borrowings outstanding as of March 31, 2016.

Revolving Credit Facility

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. As of March 31, 2016, there was $715 million of principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. However, as discussed below, commercial paper borrowings effectively reduce our borrowing capacity under this Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 1.97% as of March 31, 2016.

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 March 31, 2016, 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 March 31, 2016, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership’s credit ratings. The commitment fee is recorded as interest expense in the Partnership’s Condensed Consolidated Statements of Income.

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Commercial Paper

The Partnership has a commercial paper program, pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was $236 million outstanding under our commercial paper program as of December 31, 2015. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial program upon maturity and did not issue any additional commercial paper. There was no outstanding commercial paper as of March 31, 2016.

Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement dated as of July 31, 2015, providing for an unsecured three-year $450 million term loan agreement (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by Enable on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of March 31, 2016, there was $450 million outstanding under the 2015 Term Loan Agreement. As of March 31, 2016, the weighted average interest rate of the 2015 Term Loan Agreement was 1.80%.

The 2015 Term Loan Agreement 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 our applicable credit ratings. As of March 31, 2016, the applicable margin for LIBOR-based borrowings under the term loan agreement was 1.375% based on our credit ratings.

Senior Notes

In connection with the issuance of the 2019 Notes, 2024 Notes and 2044 Notes, the Partnership, CenterPoint Energy Resources Corp., as guarantor of the 2019 Notes and the 2024 Notes, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers, entered into a registration rights agreement whereby the Partnership and the guarantor agreed to file with the SEC a registration statement relating to a registered offer to exchange the 2019 Notes, 2024 Notes and 2044 Notes for new series of the Partnership's notes in the same aggregate principal amount as, and with terms substantially identical in all respects to, the 2019 Notes, 2024 Notes and 2044 Notes. On December 29, 2015, the Partnership completed the exchange offer.

A wholly owned subsidiary of CenterPoint Energy guaranteed collection of the Partnership's obligations under the 2019 Notes and the 2024 Notes, which expired on May 1, 2016.

As of March 31, 2016, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes have a $22 million unamortized premium at March 31, 2016, resulting in an effective interest rate of 5.7%, during the three months ended March 31, 2016. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

Financing Costs

Unamortized debt expense of $17 million and $18 million as of March 31, 2016 and December 31, 2015, respectively, is classified as either a reduction to Long-Term Debt or Other Assets in the Condensed Consolidated Balance Sheets and is being amortized over the life of the respective debt. Unamortized premium on long-term debt of $21 million and $23 million at March 31, 2016 and December 31, 2015, respectively, is classified as either Long-Term Debt or Short-Term Debt, consistent with the underlying debt instrument, in the Condensed Consolidated Balance Sheets and is being amortized over the life of the respective debt.

As of March 31, 2016, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(8) Fair Value Measurements

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

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

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

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

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

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended March 31, 2016, there were no transfers between Level 1, 2, and 3 investments.

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.

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 March 31, 2016 and December 31, 2015:

March 31, 2016	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$17	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	7	—	11	$ 7
Unobservable inputs (Level 3)	2	3	—	$ —
Total fair value	26	6	11	$ 7
Netting adjustments	(5)	(5)	—	$ —
Total	$21	$ 1	$ 11	$ 7

December 31, 2015	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$17	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	10	—	17	20
Unobservable inputs (Level 3)	4	—	—	—
Total fair value	31	3	17	20
Netting adjustments	(3)	(3)	—	—
Total	$28	$ —	$ 17	$ 20

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(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership’s operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of March 31, 2016 and December 31, 2015.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $10 million and $6 million at March 31, 2016 and December 31, 2015, 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 $0 million and $5 million at March 31, 2016 and December 31, 2015, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

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

	Commodity Contracts
	Natural gas liquids financial futures/swaps

	(In millions)
Balance as of December 31, 2015	$ 4
Losses included in earnings	(4)
Settlements	(1)
Balance as of March 31, 2016	$ (1)

Quantitative Information on Level 3 Fair Value Measurements

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

	March 31, 2016	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$(1)	$0.441 - $0.495

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 and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership's financial instruments at March 31, 2016 and December 31, 2015.

	March 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Long-term notes payable—affiliated companies (Level 2)	$—	$—	$ 363	$ 350
Revolving Credit Facility (Level 2)(1)	715	715	310	310
2015 Term Loan Agreement (Level 2)	450	450	450	450
EOIT Senior Notes (Level 2)	272	218	273	280
Enable Midstream Partners, LP 2019, 2024 and 2044 Notes (Level 2)	1,649	1,302	1,650	1,255

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(1) Borrowing capacity is reduced by our borrowings outstanding under the commercial paper program. There was zero and $236 million of commercial paper outstanding as of March 31, 2016 and December 31, 2015, respectively.

The fair value of the Partnership's Long-term notes payable—affiliated companies, Revolving Credit Facility, and 2015 Term Loan Agreement, along with the EOIT Senior Notes and Enable Midstream Partners, LP 2019, 2024 and 2044 Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

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

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

As of March 31, 2016, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

(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.

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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 futures and swaps for condensate sales are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership's keep-whole natural gas exposure associated with its processing operations and the Partnership's natural gas exposure associated with operating its gathering, transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

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

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

As of March 31, 2016 and December 31, 2015, 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 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.

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As of March 31, 2016 and December 31, 2015, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	March 31, 2016		December 31, 2015	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas — TBtu[(1)]				
Physical purchases/sales	—	48	2	51
Financial fixed futures/swaps	3	44	1	37
Financial basis futures/swaps	5	47	4	38
Crude oil (for condensate) — MBbl[(2)]				
Financial Futures/swaps	—	460	—	506
Natural gas liquids — MBbl[(3)]				
Financial Futures/swaps	—	1,551	75	1,011

(1) As of March 31, 2016, 86.1% of the natural gas contracts had durations of one year or less and 13.9% had durations of more than one year and less than two years. As of December 31, 2015, 97.7% of the natural gas contracts had durations of one year or less and 2.3% had durations of more than one year and less than two years.

(2) As of March 31, 2016, 93.5% of the condensate contracts had durations of one year or less and 6.5% had durations of more than one year and less than two years. As of December 31, 2015, 100% of the crude oil (for condensate) contracts had durations of one year or less.

(3) As of March 31, 2016, 85.5% of the natural gas liquids contracts had durations of one year or less and 14.5% had durations of more than one year and less than two years. As of December 31, 2015, 100% of the natural gas liquid contracts had durations of one year or less.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Condensed Consolidated Balance Sheets as of March 31, 2016 and December 31, 2015 that were not designated as hedging instruments for accounting purposes are as follows:

		March 31, 2016		December 31, 2015	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$ 18	$ 3	$ 17	$ 3
Physical purchases/sales	Other Current	—	—	1	—
Crude Oil (for condensate)					
Financial futures/swaps	Other Current	6	—	9	—
Natural gas liquids					
Financial Futures/swaps	Other Current	2	3	4	—
Total gross derivatives [(1)]		$ 26	$ 6	$ 31	$ 3

(1)

See Note 8 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Condensed Consolidated Balance Sheets as of March 31, 2016 and December 31, 2015.

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Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on the Partnership's Condensed Consolidated Statements of Income for the three months ended March 31, 2016 and 2015.

	Amounts Recognized in Income Three Months Ended March 31,	
	2016	2015
	(In millions)	
Natural gas financial futures/swaps gains (losses)	$ 10	$ 7
Natural gas physical purchases/sales gains (losses)	(4)	(4)
Crude Oil (for condensate) financial futures/swaps gains (losses)	1	4
Natural gas liquids financial futures/swaps gains (losses)	(4)	—
Total	$ 3	$ 7

For derivatives not designated as hedges in the tables above, amounts recognized in income for the periods ended March 31, 2016 and 2015, if any, are reported in Product Sales.

Credit-Risk Related Contingent Features in Derivative Instruments

Based upon the Partnership's senior unsecured debt rating with Moody's Investors Services or Standard & Poor's Ratings Services, the Partnership could be required to provide credit assurances to third parties, which could include letters of credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position. As of March 31, 2016, under these obligations, no cash collateral has been posted. However, based on positions as of March 31, 2016, approximately $1 million of additional collateral may be required to be posted by the Partnership.

(10) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 15	$ 9
Income taxes, net of refunds	1	—
Non-cash transactions:		
Accounts payable related to capital expenditures	42	51

(11) Related Party Transactions

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

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The Partnership's revenues from affiliated companies accounted for 9% and 8% of revenues during the three months ended March 31, 2016 and 2015, respectively. Amounts of revenues from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Gas transportation and storage service revenue — CenterPoint Energy	$ 33	$ 33
Natural gas product sales — CenterPoint Energy	1	6
Gas transportation and storage service revenue — OGE Energy	9	9
Natural gas product sales — OGE Energy	1	3
Total revenues — affiliated companies	$ 44	$ 51

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 March 31,	
	2016	2015
	(In millions)	
Cost of natural gas purchases — CenterPoint Energy	$ —	$ 1
Cost of natural gas purchases — OGE Energy	2	3
Total cost of natural gas purchases — affiliated companies	$ 2	$ 4

Prior to May 1, 2013, the Partnership had employees and reflected the associated benefit costs directly and not as corporate services. Under the terms of the MFA, effective May 1, 2013 the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership began reimbursing each of CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until the seconded employees transition from CenterPoint Energy and OGE Energy to the Partnership. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $6 million in 2016, $5 million in 2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

Prior to May 1, 2013, the Partnership received certain services and support functions from CenterPoint Energy described below. Under the terms of the MFA, effective May 1, 2013, the Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term ending on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2016 are $7 million and $3 million, respectively.

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

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Corporate Services — CenterPoint Energy	2	4
Seconded Employee Costs — OGE Energy	9	9
Corporate Services — OGE Energy	2	3
Total corporate services and seconded employees expense	$ 13	$ 16

The Partnership had outstanding long-term notes payable—affiliated companies to CenterPoint Energy at December 31, 2015 of $363 million, which were scheduled to mature in 2017. On February 18, 2016, in connection with the Private Placement of the Series A Preferred Units, the Partnership redeemed the $363 million of notes payable—affiliated companies payable to a subsidiary of CenterPoint Energy.

The Partnership recorded affiliated interest expense to CenterPoint Energy on notes payable—affiliated companies of $1 million and $2 million during the three months ended March 31, 2016 and 2015, respectively.

On February 18, 2016, the Partnership completed the private placement, with CenterPoint Energy, of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 4 for further discussion.

(12) Commitments and Contingencies

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

(13) Equity Based Compensation

The following table summarizes the Partnership’s compensation expense for the three months ended March 31, 2016 and 2015 related to performance units, restricted units, and phantom units for the Partnership’s employees and independent directors:

Three Months

	Ended March 31,	
	2016	2015
	(In millions)	
Performance units	$ 1	$ 1
Restricted units	1	2
Phantom units	—	—
Total compensation expense	$ 2	$ 3

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Units Outstanding

The Partnership periodically grants performance units, restricted units, and phantom units to certain employees under the Enable Midstream Partners, LP Long Term Incentive Plan. A summary of the activity for the Partnership's performance units, restricted units, and phantom units applicable to the Partnership's employees at March 31, 2016 and changes during 2016 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, 2015	814,510	$20.67	581,772	$21.04	9,817	$12.70
Granted	—	—	—	—	—	—
Vested	(1,685)	20.72	(78,327)	25.58	—	—
Forfeited	(44,407)	18.69	(49,839)	14.26	—	—
Units Outstanding at March 31, 2016	768,417	$20.84	453,563	$20.97	9,817	$12.70
Aggregate Intrinsic Value of Units Outstanding at March 31, 2016	$5		$3		$—	

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.

	March 31, 2016	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$9	1.80
Restricted Units	8	1.78
Phantom Units	—	0.24
Total	$17	

As of March 31, 2016, there were 11,149,474 units available for issuance under the long term incentive plan.

(14) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies excerpt in the Partnership's audited 2015 combined and 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 gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to natural gas producers, utilities and industrial customers.

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Financial data for reportable segments are as follows:

Three Months Ended March 31, 2016	Gathering and Processing	Transportation and Storage[1]	Eliminations	Total
	(In millions)			
Revenues	$333	$ 246	$ (70)	$509
Cost of natural gas and natural gas liquids	165	99	(69)	195
Operation and maintenance, General and administrative	75	41	(1)	115
Depreciation and amortization	49	32	—	81
Impairments	—	—	—	—
Taxes other than income tax	8	7	—	15
Operating income	$36	$ 67	$ —	$103
Total assets	$7,543	$ 4,888	$ (1,182)	$11,249
Capital expenditures	$121	$ 9	$ —	$130

Three Months Ended March 31, 2015	Gathering and Processing	Transportation and Storage[1]	Eliminations	Total
	(In millions)			
Revenues	$401	$ 308	$ (93)	$616
Cost of natural gas and natural gas liquids	222	163	(93)	292
Operation and maintenance, General and administrative	76	54	—	130
Depreciation and amortization	43	30	—	73
Impairments	—	—	—	—
Taxes other than income tax	8	9	—	17
Operating income	$52	$ 52	$ —	$104
Total assets as of December 31, 2015	$7,536	$ 4,976	$ (1,286)	$11,226
Capital expenditures	$215	$ 24	$ —	$239

(1) See Note 6 for discussion regarding ownership interests in SESH and related equity earnings included in the Transportation and Storage segment for the three months ended March 31, 2016 and 2015.

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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 combined and consolidated financial statements for the year ended December 31, 2015, included in our Annual Report. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read “Forward-Looking Statements.” In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are a large-scale, growth-oriented publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve current and emerging production areas in the United States, including several unconventional shale resource plays and local and regional end-user markets in the United States. Our assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers.

Our natural gas gathering and processing assets are located in Oklahoma, Texas, Arkansas, Louisiana and Mississippi and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. We also own a crude oil gathering business located in North Dakota to serve shale development in the Bakken Shale formation of the Williston Basin. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

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

Recent Developments

Construction update

The Bradley II Plant, a 200 MMcf/d cryogenic processing facility located in the Anadarko basin, is under construction and estimated to be in service in the second quarter of 2016.

The Partnership has commenced construction on the Wildhorse Plant, a 200 MMcf/d cryogenic processing facility located in the Anadarko basin, which is estimated to be in service no sooner than the second half of 2017.

Series A Preferred Units

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

Results of Operations

The following tables summarize the key components of our results of operations for the three months ended March 31, 2016 and 2015.

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Three Months Ended March 31, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$333	$ 246	$ (70)	$ 509
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	165	99	(69)	195
Gross margin [1]	168	147	(1)	314
Operation and maintenance, General and administrative	75	41	(1)	115
Depreciation and amortization	49	32	—	81
Taxes other than income tax	8	7	—	15
Operating income	$36	$ 67	$ —	$ 103
Equity in earnings of equity method affiliates	$—	$ 7	$ —	$ 7

Three Months Ended March 31, 2015	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$401	$ 308	$ (93)	$ 616
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	222	163	(93)	292
Gross margin [1]	179	145	—	324
Operation and maintenance, General and administrative	76	54	—	130
Depreciation and amortization	43	30	—	73
Taxes other than income tax	8	9	—	17
Operating income	$52	$ 52	$ —	$ 104
Equity in earnings of equity method affiliates	$—	$ 7	$ —	$ 7

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

	Three Months Ended March 31, 2016	2015
Operating Data:		
Gathered volumes—TBtu	278	286
Gathered volumes—TBtu/d	3.05	3.18
Natural gas processed volumes—TBtu	162	151
Natural gas processed volumes—TBtu/d	1.78	1.68
NGLs produced—MBbl/d [1]	73.47	65.00
NGLs sold—MBbl/d [1][2]	76.31	67.62
Condensate sold—MBbl/d	6.45	5.96
Crude Oil - Gathered volumes—MBbl/d	28.85	6.72
Transported volumes—TBtu	465	514
Transportation volumes—TBtu/d	5.11	5.72
Interstate firm contracted capacity—Bcf/d	7.17	7.82
Intrastate average deliveries—TBtu/d	1.68	1.84

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

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Gathering and Processing

Three months ended March 31, 2016 compared to three months ended March 31, 2015. Our gathering and processing segment reported operating income of $36 million in the three months ended March 31, 2016 compared to operating income of $52 million in the three months ended March 31, 2015. Operating income decreased $16 million primarily from decreased gross margin of $11 million, and an increase in depreciation and amortization of $6 million, partially offset by a decrease in operation and maintenance expenses of $1 million, during the three months ended March 31, 2016.

Our gathering and processing segment gross margin decreased $11 million primarily due to a decrease in processing margins of $9 million resulting from lower average natural gas liquids prices and lower processed volumes in the Ark-La-Tex basin offset by higher processed volumes in the Anadarko basin, combined with a decrease in unrealized gains on condensate and NGL derivatives of $8 million. Additionally, gathering margins decreased $6 million due to reduced sales on natural gas length due to lower average natural gas prices, and lower revenues on third party measurement and communication services of $1 million. These decreases were partially offset by an increase in the imbalance receivable of $9 million associated with our annual fuel rate determination and an increase in gathering fees of $3 million as a result of higher gathered volumes in the Anadarko basin. Also, crude oil gathering increased $4 million due to higher volumes in the Williston basin, offset by a decrease of $3 million from one-time project reimbursements during the three months ended March 31, 2016.

Our gathering and processing segment operation and maintenance and general and administrative expenses decreased $1 million primarily due to a decrease in payroll related costs of $3 million and lower severance charges related to 2015 workforce reductions of $2 million. These decreases were partially offset by an increase in allowance for doubtful accounts of $3 million and higher losses on sale of assets of $1 million.

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

Transportation and Storage

Three months ended March 31, 2016 compared to three months ended March 31, 2015. Our transportation and storage segment reported operating income of $67 million in the three months ended March 31, 2016 compared to operating income of $52 million in the three months ended March 31, 2015. Operating income increased $15 million primarily resulting from an increase in gross margin of $2 million, a decrease of $13 million in operation and maintenance and general and administrative expenses, and a decrease in taxes other than income tax of $2 million, partially offset by a $2 million increase in depreciation and amortization expenses for the three months ended March 31, 2016.

Our transportation and storage segment gross margin increased $2 million primarily due to higher margins of $8 million related to unrealized gains on natural gas derivatives and an increase of $1 million in gains on system optimization activities. These increases were partially offset by lower firm transportation revenues of $5 million and decreased margins from off-system transportation revenues of $2 million for the three months ended March 31, 2016.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $13 million due to a decrease in payroll related costs of $7 million, lower integration costs of $4 million, and lower severance charges related to 2015 workforce reductions of $2 million.

Our transportation and storage segment depreciation and amortization increased $2 million primarily due to additional assets placed in service.

Our transportation and storage segment taxes other than income tax decreased $2 million due to reduced ad valorem taxes.

Our transportation and storage segment recorded equity in earnings of equity method affiliates of $7 million for each of the three months ended March 31, 2016 and 2015 from our interest in SESH.

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Condensed Consolidated Interim Information

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Operating Income	$103	$104
Other Income (Expense):		
Interest expense	(23)	(20)
Equity in earnings of equity method affiliates	7	7
Other, net	—	1
Total Other Income (Expense)	(16)	(12)
Income Before Income Taxes	87	92
Income tax expense	1	1
Net Income	$86	$91
Less: Net income attributable to noncontrolling interest	—	—
Less: Series A Preferred Unit distributions	—	—
Net Income attributable to common and subordinated units	$86	$91

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Other Financial Data:		
Gross Margin (1)	$314	$324
Adjusted EBITDA (1)	215	207
Distributable cash flow (1)	174	145

(1) Gross margin, Adjusted EBITDA and distributable cash flow are defined and reconciled to their most directly comparable financial measures calculated and presented below under the caption Non-GAAP Financial Measures within this Part I, Item 2.

Three Months Ended March 31, 2016 compared to Three Months Ended March 31, 2015

Net Income attributable to the Partnership. We reported net income attributable to the Partnership of $86 million in the three months ended March 31, 2016 compared to net income attributable to the Partnership of $91 million in the three months ended March 31, 2015. The decrease in net income attributable to the Partnership of $5 million was primarily attributable to an increase in interest expense of $3 million, a decrease in operating income of $1 million and a decrease in other income and expense of $1 million in the three months ended March 31, 2016.

Interest Expense. Interest expense increased $3 million due to higher interest rates on the Partnership’s outstanding debt and an increase in the amount of outstanding debt.

Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures gross margin, Adjusted EBITDA and distributable cash flow in this report based on information in its condensed consolidated financial statements.
Gross margin, Adjusted EBITDA and distributable cash flow are supplemental financial measures that management and external users of the Partnership’s financial statements, such as industry analysts, investors, lenders and rating agencies may use, to assess:

- The Partnership’s operating performance as compared to those of other publicly traded partnerships in the midstream energy industry, without regard to capital structure or historical cost basis;

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- The ability of the Partnership's assets to generate sufficient cash flow to make distributions to its partners;
- The Partnership's ability to incur and service debt and fund capital expenditures; and
- The viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

This report includes a reconciliation of gross margin to revenues, Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest, and Adjusted EBITDA to net cash provided by operating activities, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. The Partnership believes that the presentation of gross margin, Adjusted EBITDA and distributable cash flow provides information useful to investors in assessing its financial condition and results of operations. Gross margin, Adjusted EBITDA and distributable cash flow should not be considered as alternatives to net income, operating income, revenue, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Gross margin, Adjusted EBITDA and distributable cash flow have important limitations as an analytical tool because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because gross margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in the Partnership's industry, its definitions of gross margin, Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Reconciliation of Gross Margin to Revenues:		
Revenues	$509	$616
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	195	292
Gross margin	$314	$324
Reconciliation of Adjusted EBITDA and distributable cash flow to net income attributable to common and subordinated units:		
Net income attributable to common and subordinated units	$86	$91
Add:		
Depreciation and amortization expense	81	73
Interest expense, net of interest income	23	20
Income tax expense	1	1
EBITDA	$191	$185
Add:		
Distributions from equity method affiliates[1]	20	12
Non-cash equity based compensation	2	3
Other non-cash losses	12	14
Less:		
Other non-cash gains	(3)	—
Equity in earnings of equity method affiliates	(7)	(7)
Adjusted EBITDA	$215	$207
Less:		
Adjustment for Series A Preferred Unit distribution, net [2]	(4)	—
Adjusted interest expense, net [3]	(23)	(22)
Maintenance capital expenditures	(13)	(39)

Current income taxes	(1)	(1)
Distributable cash flow	$174	$145

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	Three Months Ended March 31, 2016	2015
	(In millions)	
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:		
Net cash provided by operating activities	$117	$188
Interest expense, net of interest income	23	20
Income tax expense	1	1
Equity in earnings of equity method affiliates, net of distributions[1]	—	(5)
Non-cash equity based compensation	(2)	(3)
Other non-cash items	—	1
Changes in operating working capital which (provided) used cash:		
Accounts receivable	(24)	—
Accounts payable	87	9
Other, including changes in noncurrent assets and liabilities	(11)	(26)
EBITDA	$191	$185
Add:		
Non-cash equity based compensation	2	3
Distributions from equity method affiliates[1]	20	12
Other non-cash losses	12	14
Less:		
Other non-cash gains	(3)	—
Equity in earnings of equity method affiliates	(7)	(7)
Adjusted EBITDA	$215	$207

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(1) Distributions from equity method affiliates includes a $7 million and $12 million return on investment and a $13 million and zero return of investment for the three months ended March 31, 2016 and 2015, respectively. Equity in earnings of equity method affiliates, net of distributions only includes those distributions representing a return on investment.

(2) This amount represents the prorated quarterly cash distribution on the Series A Preferred Units declared on April 26, 2016. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made. This amount is shown net of the amount of Series A Preferred Unit distributions recognized in the Condensed Consolidated Statements of Income.

(3) Adjusted interest expense, net excludes the effect of the amortization of the premium on EOIT’s fixed rate senior notes. This exclusion is the primary reason for the difference between “Interest expense, net” and “Adjusted interest expense, net.”

Liquidity and Capital Resources

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of

March 31, 2016, we had a working capital surplus of $100 million. We utilize our revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits.

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Cash Flows

The following tables reflect cash flows for the applicable periods:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Net cash provided by operating activities	$117	$188
Net cash used in investing activities	(117)	(245)
Net cash provided by financing activities	34	53

Operating Activities

The decrease of $71 million, or 38%, in net cash provided by operating activities for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015 was primarily due to timing of payments to suppliers, receipts from customers, and changes in other working capital assets and liabilities.

Investing Activities

The decrease of $128 million, or 52%, in net cash used in investing activities for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015 was primarily due to lower capital expenditures of $109 million.

Financing Activities

Net cash provided by financing activities decreased $19 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. Our primary financing activities consist of the following:

	Three Months Ended March 31,	
	2016	2015
	(In millions)	
Net proceeds from Revolving Credit Facility	405	—
Proceeds (repayments) from commercial paper program	(236)	183
Repayment of notes payable—affiliated companies	(363)	—
Proceeds from issuance of Series A Preferred Units, net of issuance costs	362	—
Distributions to partners	(134)	(130)

Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement providing for an unsecured three-year $450 million term loan agreement (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by Enable on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of March 31, 2016 there was $450 million outstanding under the 2015 Term Loan Agreement.

The 2015 Term Loan Agreement 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 our applicable credit ratings. As of March 31, 2016, the applicable margin for LIBOR-based borrowings under the term loan agreement was 1.375% based on our credit ratings. As of March 31, 2016, the weighted average interest rate of the 2015 Term Loan Agreement was 1.80%.

Revolving Credit Facility

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. The Revolving Credit Facility is discussed in Note 7 of the condensed consolidated financial statements. As of March 31, 2016, there were $715 million of principal

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advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 1.97% as of March 31, 2016. Commercial paper borrowings effectively reduce our borrowing capacity under this Revolving Credit Facility. As of March 31, 2016, we had no outstanding borrowings under our commercial paper program.

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 March 31, 2016, 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 March 31, 2016, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership’s credit ratings. The commitment fee is recorded as interest expense in the Partnership’s Combined and Consolidated Statements of Income.

Preferred Equity Issuance

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, with CenterPoint Energy, resulting in proceeds of $362 million, net of issuance costs. See Part 1, Note 4 for further discussion.

Sources of Liquidity

As of March 31, 2016, our sources of liquidity included:

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

Capital Requirements

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

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

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

Distributions

On April 26, 2016, 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 and subordinated units for the period ended March 31, 2016. Additionally, the board of directors of Enable GP declared a prorated quarterly cash distribution of $0.2917 on the Partnership's outstanding Series A Preferred Units. The distributions will be paid May 13, 2016 to unitholders of record as of the close of business on May 6, 2016.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

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Credit Risk

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

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 Combined and Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" in our Annual Report on Form 10-K for the year ended December 31, 2015. The accounting policies and estimates used in preparing our interim Condensed Consolidated Financial Statements for the three months ended March 31, 2016 are the same as those described in our Annual Report on Form 10-K for the year ended December 31, 2015.

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 long-term, fee-based contracts that include minimum volume commitments and/or demand fees, we are also exposed to changes in the prices of natural gas 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.

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately 15% of our total gross margin for the twelve months ending December 31, 2016 is directly exposed to changes in commodity prices, excluding the impact of hedges.

Commodity price risk is estimated as the potential loss in value resulting from a hypothetical 10% decline in prices over the next nine months. Based on a sensitivity analysis, a 10% decrease in prices from forecasted levels would decrease net income by approximately $5 million for natural gas and $6 million for condensate and NGLs, excluding the impact of hedges, for the remaining nine months ending December 31, 2016.

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 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 $1,165 million outstanding borrowings under the 2015 Term Loan Agreement and Revolving Credit Facility as of March 31, 2016, and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $12 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of March 31, 2016. Based on such evaluation, our management has concluded that, as of March 31, 2016, 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 March 31, 2016, that have materially affected, or that are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. Risk factors relating to the Partnership are set forth under "Risk Factors" in our Annual Report. No other material changes to such risk factors have occurred during the three months ended March 31, 2016 with the exception of the items discussed below.

Our Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

Our 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership (our "Series A Preferred Units"), issued in February 2016, rank senior to all of our other classes or series of equity securities with respect to distribution rights and rights upon liquidation. We cannot declare or pay a distribution to our common or subordinated unitholders for any quarter unless full distributions have been or contemporaneously are being paid on all outstanding Series A Preferred Units for such quarter. These preferences could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

Holders of the Series A Preferred Units will receive, on a non-cumulative basis and if and when declared by our general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10% on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date, and an annual rate of LIBOR plus a spread of 850 bps on the stated liquidation preference thereafter. In connection with certain transfers of the Series A Preferred Units, the Series A Preferred Units will automatically convert into one or more new series of preferred units (the “other preferred units”) on the later of the date of transfer or the second anniversary of the date of issue. The other preferred units will have the same terms as our Series A Preferred Units except that unpaid distributions on the other preferred units will accrue from the date of their issuance on a cumulative basis until paid. Our Series A Preferred Units are convertible into common units by the holders of such units in certain circumstances. Payment of distributions on our Series A Preferred Units, or on the common units issued following the conversion of such Series A Preferred Units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Our obligations to the holders of Series A Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

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Our Series A Preferred Units contain covenants that may limit our business flexibility.

Our Series A Preferred Units contain covenants preventing us from taking certain actions without the approval of the holders of 66 2⁄3% of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede our ability to take certain actions that management or our board of directors may consider to be in the best interests of our unitholders. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend the Partnership Agreement in any manner that would or could reasonably be expected to have a material adverse effect on the rights, preferences, obligations or privileges of the Series A Preferred Units. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) create or issue certain party securities with proceeds in an aggregate amount in excess of $700 million or create or issue any senior securities or (B) subject to our right to redeem the Series A Preferred Units, approve certain fundamental transactions.

Our Series A Preferred Units are required to be redeemed in certain circumstances if they are not eligible for trading on the NYSE, and we may not have sufficient funds to redeem our Series A Preferred Units if we are required to do so.

The holders of our Series A Preferred Units may request that we list those units for trading on the NYSE. If we are unable to list the Series A Preferred Units in certain circumstances, we will be required to redeem the Series A Preferred Units. There can be no assurance that we would have sufficient financial resources available to satisfy our obligation to redeem the Series A Preferred Units. In addition, mandatory redemption of our Series A Preferred Units could have a material adverse effect on our business, financial position, results of operations and ability to make quarterly cash distributions to our unitholders.

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

We may not have sufficient available cash each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins we realize with respect to the volume of natural gas, NGLs and crude oil that we handle;
- the prices of, levels of production of, and demand for natural gas, NGLs and crude oil;
- the volume of natural gas, NGLs and crude oil we gather, compress, treat, dehydrate, process, fractionate, transport and store;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- adverse effects of governmental and environmental regulation;
- the level of our operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level and timing of capital expenditures we make;
- the cost of acquisitions;

•our debt service requirements and other liabilities;
•fluctuations in working capital needs;
•our ability to borrow funds and access capital markets;
•restrictions contained in our debt agreements;
•the amount of cash reserves established by our general partner
•distributions paid on our Series A Preferred Units; and

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- other business risks affecting our cash levels.

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

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

Our general partner and its affiliates, including CenterPoint Energy and OGE Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Affiliates of CenterPoint Energy and OGE Energy own and control our general partner and appoint all of the officers and directors of our general partner. Some of the directors of our general partner are also directors of CenterPoint Energy or OGE Energy. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to CenterPoint Energy and OGE Energy. Conflicts of interest will arise between CenterPoint Energy, OGE Energy and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of CenterPoint Energy and OGE Energy over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither the Partnership Agreement nor any other agreement requires CenterPoint Energy or OGE Energy to pursue a business strategy that favors us. The directors and officers of CenterPoint Energy and OGE Energy have a fiduciary duty to make decisions in the best interests of the stockholders of their respective companies, which may be contrary to our interests. CenterPoint Energy and OGE Energy may choose to shift the focus of their investment and growth to areas not served by our assets. In addition, CenterPoint Energy is the holder of our Series A Preferred Units and may favor its interests in voting in favor of actions relating to such units, including voting in favor of making distributions on such Series A Preferred Units even if no distributions are made on the common units.
- Our general partner is allowed to take into account the interests of parties other than us, such as CenterPoint Energy and OGE Energy, in resolving conflicts of interest.
- Some of the directors of our general partner are also directors of CenterPoint Energy or OGE Energy and will owe fiduciary duties to their respective companies. These individuals may also devote significant time to the business of CenterPoint Energy and OGE Energy.
- The Partnership Agreement replaces the fiduciary duties that would otherwise be owed to us by our general partner with contractual standards governing its duties, limits our general partner's liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Disputes may arise under our commercial agreements with CenterPoint Energy and OGE Energy.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of distributable cash flow.
- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is

distributed to our unitholders and the ability of the subordinated units to convert to common units.

- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- The Partnership Agreement permits us to classify up to $300 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash

may be used to fund distributions on our subordinated or general partner units or to our general partner in respect of the incentive distribution rights.

- The Partnership Agreement does not prohibit our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 90% of the common units. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may transfer its incentive distribution rights without unitholder approval.
- Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the Board of Directors or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

We may issue additional units without your approval, which would dilute your existing ownership interests.

The Partnership Agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of distributable cash flow on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

In addition, upon a change of control, our Series A Preferred Units are convertible into common units at the option of the holders of such units. If a substantial portion of the Series A Preferred Units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted Series A Preferred Units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Affiliates of our general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units.

As of March 31, 2016, subsidiaries of CenterPoint Energy and OGE Energy hold an aggregate of 136,983,998 common units and 207,855,430 subordinated units, and CenterPoint Energy holds 14,520,000 Series A Preferred Units. Upon a change of control, our Series A Preferred Units are convertible into common units at the option of the holders of such units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier under certain circumstances. In addition, we have agreed to provide CenterPoint Energy, OGE Energy and ArcLight with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our general partner and its affiliates own more than 90% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price, as calculated pursuant to the terms of the Partnership Agreement. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any positive return on their investment. Our unitholders may also incur a tax liability upon any such sale of their units. As of March 31, 2016, affiliates of our general partner owned approximately 32.4% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), affiliates of our general partner will own approximately 81.7% of our aggregate outstanding common units. If we assume the conversion of our Series A Preferred Units, affiliates of our general partner will own an additional 83.4% of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases.

We may incur significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs.

The U.S. Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located in “high consequence areas,” which are those areas where a leak or rupture could do the most harm. The regulations require operators, including us, to, among other things:

- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, in August 2011, PHMSA published an advance notice of proposed rulemaking (ANPRM) in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. On April 8, 2016, the Pipeline and Hazardous Materials Safety Administration published a notice of proposed rulemaking (NPRM) responding to several of the integrity management topics raised in the August 2011 ANPRM and proposing new requirements to address safety issues for natural gas transmission and gathering lines that have arisen since the issuance of the ANPRM. The proposed rule would strengthen existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. Comments on the April 8, 2016 NPRM are currently due by June 7, 2016. PHMSA published a similar NPRM for hazardous liquids (including oil) pipelines on October 13, 2015. That proposed rule would extend regulatory reporting requirements to all liquid gathering lines, require additional event-driven and periodic inspections, require use of leak detection systems on all hazardous liquid pipelines, modify repair criteria, and require certain pipelines to eventually accommodate inline inspection tools. Comments were due by January 8, 2016, and further action is pending. We are still monitoring and evaluating the effect of these proposed requirements on our operations.

Although many of our pipelines fall within a class that is currently not subject to these requirements, we may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with our non-exempt pipelines. This work is part of our normal integrity management program and we do not expect to incur any extraordinary costs during 2016 to complete the testing required by existing DOT regulations and their state counterparts. We have not estimated the costs for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. In addition, rulemakings such as the ones discussed in the October 13, 2015 and April 8, 2016 NPRMs could expand the scope of the integrity management program and other related pipeline safety programs to include additional requirements or previously exempt pipelines. We have not estimated the cost of complying with such future requirements.

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Item 6. Exhibits

The following exhibits are filed herewith:

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated by reference to a prior filing as indicated.

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.

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	Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Registrant’s Form 8-K filed February 19, 2016	File No. 001-36413	Exhibit 3.1
4.1	Specimen Unit Certificate representing common units (included with Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP as Exhibit A thereto)	Registrant’s Form 8-K filed April 22, 2014	File No. 001-36413	Exhibit 3.1
4.2	Indenture, dated as of May 27, 2014, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Registrant’s Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.1
4.3	First Supplemental Indenture, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee.	Registrant’s Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.2
4.4	Registration Rights Agreement, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers.	Registrant’s Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.3
4.5				

	Registration Rights Agreement, dated as of February 18, 2016, by and between Enable Midstream Partners, LP and CenterPoint Energy, Inc.	Registrant's Form 8-K filed February 19, 2016	File No. 001-36413	Exhibit 4.1
10.1	Purchase Agreement by and between Enable Midstream Partners, LP and CenterPoint Energy, Inc. dated January 28, 2016	Registrant's Form 8-K filed February 1, 2016	File No. 001-36413	Exhibit 10.1
+10.2	Special Severance Agreement and General Release by and between Enable Midstream Services, LLC and Paul A. Weissgarber			
+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			
+99.1	Guarantee Agreement dated as of May 1, 2013 among CenterPoint Energy Field Services LP and Enogex LLC			
+101.INS	XBRL Instance Document.			
+101.SCH	XBRL Taxonomy Schema Document.			
+101.PRE	XBRL Taxonomy Presentation Linkbase Document.			
+101.LAB	XBRL Taxonomy Label Linkbase Document.			
+101.CAL	XBRL Taxonomy Calculation Linkbase Document.			
+101.DEF	XBRL Definition Linkbase Document.			

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SIGNATURE

Pursuant to the requirements of the Securities 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:	May 4, 2016	By:	/s/ Tom Levescy
			Tom Levescy
			Senior Vice President, Chief Accounting Officer and Controller
			(Principal Accounting Officer)