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

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No.: 1-16335

Magellan Midstream Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**73-1599053**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**

One Williams Center, P.O. Box 22186, Tulsa, Oklahoma 74121-2186
(Address of principal executive offices and zip code)
(918) 574-7000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company)
Smaller reporting company ☐ Emerging growth company ☐

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

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

As of August 1, 2017, there were 228,024,556 outstanding limited partner units of Magellan Midstream Partners, L.P. that trade on the New York Stock Exchange under the ticker symbol "MMP."

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FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017
Transportation and terminals revenue	$ 392,240	$ 433,239	$ 762,315	$ 825,910
Product sales revenue	123,689	182,004	270,251	427,624
Affiliate management fee revenue	2,968	4,197	6,147	7,980
Total revenue	518,897	619,440	1,038,713	1,261,514
Costs and expenses:				
Operating	134,183	145,294	257,096	276,886
Cost of product sales	95,703	145,975	209,288	318,851
Depreciation and amortization	43,302	48,896	87,056	96,194
General and administrative	34,554	43,393	75,230	83,674
Total costs and expenses	307,742	383,558	628,670	775,605
Earnings of non-controlled entities	15,339	25,576	32,967	47,022
Operating profit	226,494	261,458	443,010	532,931
Interest expense	48,686	51,546	92,410	102,758
Interest income	(404)	(256)	(765)	(548)
Interest capitalized	(7,130)	(3,183)	(13,266)	(7,380)
Gain on exchange of interest in non-controlled entity	(1,244)	—	(28,144)	—
Other expense (income)	(1,958)	2,043	(3,710)	3,213
Income before provision for income taxes	188,544	211,308	396,485	434,888
Provision for income taxes	685	908	1,556	1,752
Net income	$ 187,859	$ 210,400	$ 394,929	$ 433,136
Basic net income per limited partner unit	$ 0.82	$ 0.92	$ 1.73	$ 1.90
Diluted net income per limited partner unit	$ 0.82	$ 0.92	$ 1.73	$ 1.90
Weighted average number of limited partner units outstanding used for basic net income per unit calculation(1)	227,952	228,192	227,889	228,151
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation(1)	227,983	228,245	227,921	228,202

(1) See Note 10–*Long-Term Incentive Plan* for additional information regarding our weighted average unit calculations.

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited, in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017
Net income	$ 187,859	$ 210,400	$ 394,929	$ 433,136
Other comprehensive income:				
Derivative activity:				
Net gain (loss) on cash flow hedges[1]	(8,631)	(2,802)	(21,109)	(1,507)
Reclassification of net (gain) loss on cash flow hedges to income[1]	388	739	776	1,479
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:				
Amortization of prior service credit[2]	(974)	(46)	(1,947)	(91)
Amortization of actuarial loss[2]	1,292	1,983	2,693	3,211
Settlement cost[2]	—	361	—	1,726
Total other comprehensive income (loss)	(7,925)	235	(19,587)	4,818
Comprehensive income	$ 179,934	$ 210,635	$ 375,342	$ 437,954

(1) See Note 8–*Derivative Financial Instruments* for details of the amount of gain/loss recognized in accumulated other comprehensive loss (“AOCL”) for derivative financial instruments and the amount of gain/loss reclassified from AOCL into income.

(2) See Note 6–*Employee Benefit Plans* for details of the changes in employee benefit plan assets and benefit obligations recognized in AOCL.

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2016	June 30, 2017
ASSETS		**(Unaudited)**
Current assets:		
Cash and cash equivalents	$ 14,701	$ 5,471
Trade accounts receivable	105,689	113,233
Other accounts receivable	25,761	12,636
Inventory	134,378	119,451
Energy commodity derivatives contracts, net	—	4,250
Energy commodity derivatives deposits	49,899	4,492
Other current assets	39,966	66,123
Total current assets	370,394	325,656
Property, plant and equipment	6,783,737	7,048,502
Less: Accumulated depreciation	1,507,996	1,592,035
Net property, plant and equipment	5,275,741	5,456,467
Investments in non-controlled entities	931,255	976,456
Long-term receivables	23,870	22,532
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $2,136 and $1,228 at December 31, 2016 and June 30, 2017, respectively)	51,976	52,925
Other noncurrent assets	65,577	43,426
Total assets	$ 6,772,073	$ 6,930,722
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 77,248	$ 103,100
Accrued payroll and benefits	45,690	40,181
Accrued interest payable	65,643	65,459
Accrued taxes other than income	50,166	43,409
Environmental liabilities	10,249	6,466
Deferred revenue	101,891	115,023
Accrued product purchases	51,600	46,803
Energy commodity derivatives contracts, net	30,738	—
Energy commodity derivatives deposits	—	119
Other current liabilities	48,431	36,015
Total current liabilities	481,656	456,575
Long-term debt, net	4,087,192	4,231,912
Long-term pension and benefits	71,461	68,444
Other noncurrent liabilities	25,868	27,137
Environmental liabilities	13,791	12,385
Commitments and contingencies		
Partners' capital:		
Limited partner unitholders (227,784 units and 228,025 units outstanding at December 31, 2016 and June 30, 2017, respectively)	2,193,346	2,230,692
Accumulated other comprehensive loss	(101,241)	(96,423)
Total partners' capital	2,092,105	2,134,269
Total liabilities and partners' capital	$ 6,772,073	$ 6,930,722

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2017
Operating Activities:		
Net income	$ 394,929	$ 433,136
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	87,056	96,194
Loss on sale and retirement of assets	3,263	5,331
Earnings of non-controlled entities	(32,967)	(47,022)
Distributions of earnings from investments in non-controlled entities	31,080	46,754
Equity-based incentive compensation expense	10,059	10,717
Settlement cost, amortization of prior service credit and actuarial loss	746	4,846
Gain on exchange of interest in non-controlled entity	(28,144)	—
Changes in operating assets and liabilities:		
Trade accounts receivable and other accounts receivable	(10,703)	2,681
Inventory	(25,562)	14,927
Energy commodity derivatives contracts, net of derivatives deposits	(17,121)	10,538
Accounts payable	9,125	13,132
Accrued payroll and benefits	(14,937)	(5,509)
Accrued interest payable	10,998	(184)
Accrued taxes other than income	(6,463)	(6,757)
Accrued product purchases	(8,858)	(4,797)
Deferred revenue	16,935	13,132
Current and noncurrent environmental liabilities	(2,695)	(5,189)
Other current and noncurrent assets and liabilities	(9,673)	(9,519)
Net cash provided by operating activities	407,068	572,411
Investing Activities:		
Additions to property, plant and equipment, net[(1)]	(310,133)	(281,504)
Proceeds from sale and disposition of assets	4,756	4,886
Investments in non-controlled entities	(109,933)	(55,273)
Distributions in excess of earnings of non-controlled entities	1,942	11,152
Net cash used by investing activities	(413,368)	(320,739)
Financing Activities:		
Distributions paid	(361,605)	(393,912)
Net commercial paper borrowings (repayments)	(255,966)	146,885
Borrowings under long-term notes	649,187	—
Debt placement costs	(5,408)	—
Payments associated with settlement of equity-based incentive compensation	(14,376)	(13,875)
Net cash provided (used) by financing activities	11,832	(260,902)
Change in cash and cash equivalents	5,532	(9,230)
Cash and cash equivalents at beginning of period	28,731	14,701
Cash and cash equivalents at end of period	$ 34,263	$ 5,471
Supplemental non-cash investing and financing activities:		
Issuance of limited partner units in settlement of equity-based incentive plan awards	$ 7,092	$ 1,669
(1) Additions to property, plant and equipment	$ (321,085)	$ (289,570)
Changes in accounts payable and other current liabilities related to capital expenditures	10,952	8,066
Additions to property, plant and equipment, net	$ (310,133)	$ (281,504)

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization, Description of Business and Basis of Presentation

Organization

Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. Magellan Midstream Partners, L.P. is a Delaware limited partnership and its limited partner units are traded on the New York Stock Exchange under the ticker symbol “MMP.” Magellan GP, LLC, a wholly-owned Delaware limited liability company, serves as its general partner.

Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of June 30, 2017, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, our condensate splitter and storage facilities with an aggregate storage capacity of approximately 27 million barrels, of which approximately 17 million barrels are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

Terminology common in our industry includes the following terms, which describe products that we transport, store and distribute through our pipelines and terminals:

- *refined products* are the output from refineries and are primarily used as fuels by consumers. Refined products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil. Collectively, diesel fuel and heating oil are referred to as distillates;

- *liquefied petroleum gases, or LPGs,* are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

- *blendstocks* are blended with refined products to change or enhance their characteristics such as increasing a gasoline’s octane or oxygen content. Blendstocks include alkylates, oxygenates and natural gasoline;

- *heavy oils and feedstocks* are used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil;

- *crude oil and condensate* are used as feedstocks by refineries and petrochemical facilities;

- *biofuels*, such as ethanol and biodiesel, are increasingly required by government mandates; and

- *ammonia* is primarily used as a nitrogen fertilizer.

Except for ammonia, we use the term *petroleum products* to describe any, or a combination, of the above-noted products.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Basis of Presentation

In the opinion of management, our accompanying consolidated financial statements which are unaudited, except for the consolidated balance sheet as of December 31, 2016, which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of June 30, 2017, the results of operations for the three and six months ended June 30, 2016 and 2017 and cash flows for the six months ended June 30, 2016 and 2017. The results of operations for the six months ended June 30, 2017 are not necessarily indicative of the results to be expected for the full year ending December 31, 2017 for several reasons. Profits from our butane blending activities are realized largely during the first and fourth quarters of each year. Additionally, gasoline demand, which drives transportation volumes and revenues on our pipeline systems, generally trends higher during the summer driving months. Further, the volatility of commodity prices impacts the profits from our commodity activities and, to a lesser extent, the volume of petroleum products we transport on our pipelines.

Pursuant to the rules and regulations of the Securities and Exchange Commission, the financial statements in this report do not include all of the information and notes normally included with financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”). These financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2016.

Use of Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our consolidated financial statements, as well as their impact on the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

New Accounting Pronouncements

In March 2017, the Financial Accounting Standards Board (“ FASB”) issued Accounting Standards Update (“ASU”) 2017-07, *Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. This ASU requires companies that offer postretirement benefits to present the service cost, which is the amount an employer has to set aside each period to cover the benefits, in the same line item with other employee compensation costs. Other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. Additionally, only the service cost component will be eligible for capitalization when applicable.

Public companies must comply with the new requirements under ASU 2017-07 for fiscal years that start after December 15, 2017, and the amendments must be applied retrospectively except for the capitalization change, which should be applied prospectively. Early adoption is allowed, and we elected to adopt ASU 2017-07 as of January 1, 2017. Prior to adoption, we expensed all components of pension expense through salaries and wages, which impacted operating income. We are now recording only the service component of pension expense to salaries and wages, with the remainder of the expense being recorded to other income and expense below operating profit. Comparative prior periods have been restated for this change. The changes were not material to our financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. This ASU requires lessees to recognize a right of use asset and lease liability on the balance sheet for all leases, with the exception of short-term leases. The

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

new accounting model for lessors remains largely the same, although some changes have been made to align it with the new lessee model and the new revenue recognition guidance. This update also requires companies to include additional disclosures regarding their lessee and lessor agreements. Public companies are required to adopt the standard for financial reporting periods that start after December 15, 2018, although early adoption is permitted. We are currently in the process of evaluating the impact this new standard will have on our financial statements.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory*. Prior to this update, reporting entities were required to measure inventory at the lower of cost or market. Market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. Under this update, inventory is to be measured at the lower of cost or net realizable value, which is defined as the estimated selling price in the ordinary course of business, less reasonable predictable costs of completion, disposal and transportation. This ASU became effective for fiscal years beginning after December 15, 2016 and interim periods within those fiscal years. We adopted this standard on January 1, 2017, and it did not have a material impact on our results of operations, financial position or cash flows as we have historically measured our inventory at the lower of cost or net realizable value, as described above.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers.* This ASU amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods or services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. We will adopt this ASU as required on January 1, 2018, using the full retrospective method of adoption. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

2. Product Sales Revenue

The amounts reported as product sales revenue on our consolidated statements of income include revenue from the physical sale of petroleum products and mark-to-market adjustments from exchange-based futures contracts. See Note 8 – *Derivative Financial Instruments* for a discussion of our commodity hedging strategies and how our futures contracts impact product sales revenue. All of the petroleum products inventory we physically sell associated with our butane blending and fractionation activities, as well as the barrels from product gains we obtain from our operations, including tender deductions, are reported as product sales revenue on our consolidated statements of income.

For the three and six months ended June 30, 2016 and 2017, product sales revenue included the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017
Physical sale of petroleum products	$ 135,459	$ 167,790	$ 266,039	$ 384,730
Change in value of futures contracts	(11,770)	14,214	4,212	42,894
Total product sales revenue	$ 123,689	$ 182,004	$ 270,251	$ 427,624

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately as each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenue from affiliates and external customers, operating expenses, cost of product sales and earnings of non-controlled entities.

We believe that investors benefit from having access to the same financial measures used by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a GAAP measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Operating profit includes depreciation and amortization expense and general and administrative ("G&A") expense that management does not consider when evaluating the core profitability of our separate operating segments.

	Three Months Ended June 30, 2016 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 247,842	$ 101,340	$ 43,058	$ —	$ 392,240
Product sales revenue	122,311	(28)	1,406	—	123,689
Affiliate management fee revenue	124	2,486	358	—	2,968
Total revenue	370,277	103,798	44,822	—	518,897
Operating expenses	98,513	20,555	16,278	(1,163)	134,183
Cost of product sales	94,392	1,016	295	—	95,703
(Earnings) losses of non-controlled entities	38	(14,711)	(666)	—	(15,339)
Operating margin	177,334	96,938	28,915	1,163	304,350
Depreciation and amortization expense	24,971	9,062	8,106	1,163	43,302
G&A expense	20,506	9,149	4,899	—	34,554
Operating profit	$ 131,857	$ 78,727	$ 15,910	$ —	$ 226,494

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended June 30, 2017 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 277,883	$ 108,455	$ 47,794	$ (893)	$ 433,239
Product sales revenue	161,723	19,403	878	—	182,004
Affiliate management fee revenue	353	3,474	370	—	4,197
Total revenue	439,959	131,332	49,042	(893)	619,440
Operating expenses	100,713	31,410	15,375	(2,204)	145,294
Cost of product sales	125,220	18,607	2,148	—	145,975
(Earnings) losses of non-controlled entities	(422)	(24,494)	(660)	—	(25,576)
Operating margin	214,448	105,809	32,179	1,311	353,747
Depreciation and amortization expense	27,005	12,507	8,073	1,311	48,896
G&A expense	26,720	11,071	5,602	—	43,393
Operating profit	$ 160,723	$ 82,231	$ 18,504	$ —	$ 261,458

	Six Months Ended June 30, 2016 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 472,592	$ 203,068	$ 86,655	$ —	$ 762,315
Product sales revenue	266,227	1,715	2,309	—	270,251
Affiliate management fee revenue	204	5,270	673	—	6,147
Total revenue	739,023	210,053	89,637	—	1,038,713
Operating expenses	184,287	41,681	33,483	(2,355)	257,096
Cost of product sales	206,248	2,361	679	—	209,288
(Earnings) losses of non-controlled entities	80	(31,690)	(1,357)	—	(32,967)
Operating margin	348,408	197,701	56,832	2,355	605,296
Depreciation and amortization expense	50,091	18,931	15,679	2,355	87,056
G&A expense	45,736	18,888	10,606	—	75,230
Operating profit	$ 252,581	$ 159,882	$ 30,547	$ —	$ 443,010

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Six Months Ended June 30, 2017 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$ 519,788	$ 213,508	$ 94,201	$ (1,587)	$ 825,910
Product sales revenue	401,893	22,506	3,225	—	427,624
Affiliate management fee revenue	682	6,608	690	—	7,980
Total revenue	922,363	242,622	98,116	(1,587)	1,261,514
Operating expenses	194,246	58,828	28,030	(4,218)	276,886
Cost of product sales	292,901	21,184	4,766	—	318,851
(Earnings) losses of non-controlled entities	(533)	(45,144)	(1,345)	—	(47,022)
Operating margin	435,749	207,754	66,665	2,631	712,799
Depreciation and amortization expense	53,971	23,363	16,229	2,631	96,194
G&A expense	51,621	21,110	10,943	—	83,674
Operating profit	$ 330,157	$ 163,281	$ 39,493	$ —	$ 532,931

4. Investments in Non-Controlled Entities

Our investments in non-controlled entities at June 30, 2017 were comprised of:

Entity	Ownership Interest
BridgeTex Pipeline Company, LLC (“BridgeTex”)	50%
Double Eagle Pipeline LLC (“Double Eagle”)	50%
HoustonLink Pipeline Company, LLC (“HoustonLink”)	50%
Powder Springs Logistics, LLC (“Powder Springs”)	50%
Saddlehorn Pipeline Company, LLC (“Saddlehorn”)	40%
Seabrook Logistics, LLC (“Seabrook”)	50%
Texas Frontera, LLC (“Texas Frontera”)	50%

We serve as operator of BridgeTex, HoustonLink, Powder Springs, Saddlehorn, Texas Frontera and the pipeline activities of Seabrook. We receive fees for management services as well as reimbursement or payment to us for certain direct operational payroll and other overhead costs. The management fees we have received are reported as affiliate management fee revenue on our consolidated statements of income. Cost reimbursements we receive from these entities in connection with our operating services are included as reductions to costs and expenses on our consolidated statements of income and totaled $1.0 million and $1.4 million during the three months ended June 30, 2016 and 2017, respectively, and $1.5 million and $2.4 million during the six months ended June 30, 2016 and 2017, respectively.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We recorded the following revenue from certain of these non-controlled entities in our consolidated statements of income (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017
Transportation and terminals revenue:				
BridgeTex, capacity lease	$ 8.8	$ 9.0	$ 17.7	$ 17.9
Double Eagle, throughput revenue	$ 0.9	$ 1.0	$ 1.6	$ 1.8
Saddlehorn, storage revenue	$ —	$ 0.6	$ —	$ 1.1

Our consolidated balance sheets reflected the following balances related to our investments in non-controlled entities (in millions):

	December 31, 2016		June 30, 2017	
	Trade Accounts Receivable	Other Accounts Receivable	Trade Accounts Receivable	Other Accounts Receivable
Double Eagle	$ 0.3	$ —	$ 0.4	$ —
Powder Springs	$ —	$ —	$ —	$ 1.0
Saddlehorn	$ —	$ 0.1	$ —	$ 0.1
BridgeTex	$ —	$ —	$ —	$ 0.1

In addition to the transactions noted above, we incurred charges of $3.9 million for transportation of crude oil at published spot tariff rates on the BridgeTex pipeline during the three months ended June 30, 2017. We recorded these charges as cost of product sales in our consolidated statements of income. We recognized an affiliate payable to BridgeTex on our consolidated balance sheets as of June 30, 2017 in the amount of $1.9 million in connection with this activity.

In January 2017, we entered into an agreement to guarantee our 50% pro rata share, up to $50.0 million, of obligations under Powder Springs' credit facility. At June 30, 2017, we recognized a $0.8 million other current liability and a corresponding increase in our investment in non-controlled entities on our consolidated balance sheet to reflect the fair value of this guarantee.

In February 2016, we transferred a 50% membership interest in Osage Pipe Line Company, LLC ("Osage") to an affiliate of HollyFrontier Corporation. In conjunction with this transaction, we entered into several commercial agreements with affiliates of HollyFrontier Corporation, which we recorded at that time as a $43.7 million intangible asset and an $8.3 million other receivable on our consolidated balance sheets. The intangible asset will be amortized over the 20-year life of the contracts received. We recognized a $28.1 million non-cash gain in 2016 in relation to this transaction.

The financial results from Texas Frontera are included in our marine storage segment, the financial results from BridgeTex, Double Eagle, HoustonLink, Osage, Saddlehorn and Seabrook are included in our crude oil segment and the financial results from Powder Springs are included in our refined products segment, each as earnings of non-controlled entities.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of our investments in non-controlled entities follows (in thousands):

Investments at December 31, 2016	**$ 931,255**
Additional investment	56,085
Earnings of non-controlled entities:	
Proportionate share of earnings	48,196
Amortization of excess investment and capitalized interest	**(1,174)**
Earnings of non-controlled entities	47,022
Less:	
Distributions of earnings from investments in non-controlled entities	46,754
Distributions in excess of earnings of non-controlled entities	11,152
Investments at June 30, 2017	**$ 976,456**

5. Inventory

Inventory at December 31, 2016 and June 30, 2017 was as follows (in thousands):

	December 31, 2016	June 30, 2017
Refined products	$ 54,285	$ 20,449
Transmix	28,319	35,415
Liquefied petroleum gases	24,868	43,442
Crude oil	20,839	13,566
Additives	6,067	6,579
Total inventory	$ 134,378	$ 119,451

6. Employee Benefit Plans

We sponsor a defined contribution plan in which we match our employees' qualifying contributions, resulting in additional expense to us. Expenses related to the defined contribution plan were $2.4 million and $2.1 million for the three months ended June 30, 2016 and 2017, respectively, and $5.4 million and $5.4 million for the six months ended June 30, 2016 and 2017, respectively.

Additionally, we sponsor two union pension plans that cover certain union employees and a pension plan for all non-union employees, and a postretirement benefit plan for selected employees. Net periodic benefit expense for the three and six months ended June 30, 2016 and 2017 was as follows (in thousands):

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended June 30, 2016		Three Months Ended June 30, 2017	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Components of net periodic benefit costs:				
Service cost	$ 4,405	$ 62	$ 5,230	$ 66
Interest cost[1]	1,933	110	2,582	123
Expected return on plan assets[1]	(2,331)	—	(2,646)	—
Amortization of prior service credit[1]	(45)	(929)	(46)	—
Amortization of actuarial loss[1]	1,107	185	1,783	200
Settlement cost[1]	—	—	361	—
Net periodic benefit cost (credit)	$ 5,069	$ (572)	$ 7,264	$ 389

	Six Months Ended June 30, 2016		Six Months Ended June 30, 2017	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Components of net periodic benefit costs:				
Service cost	$ 9,093	$ 123	$ 10,248	$ 131
Interest cost[1]	3,978	220	4,932	245
Expected return on plan assets[1]	(4,459)	—	(5,133)	—
Amortization of prior service credit[1]	(90)	(1,857)	(91)	—
Amortization of actuarial loss[1]	2,324	369	2,811	400
Settlement cost[1]	—	—	1,726	—
Net periodic benefit cost (credit)	$ 10,846	$ (1,145)	$ 14,493	$ 776

(1) Upon adoption of ASU 2017-07, *Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, these components of net periodic benefit cost (credit) are reported on the consolidated statements of income as other expense (income). See Note 1 – *Organization, Description of Business and Basis of Presentation - New Accounting Pronouncements* for further details about this accounting change.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The changes in AOCL related to employee benefit plan assets and benefit obligations for the three and six months ended June 30, 2016 and 2017 were as follows (in thousands):

	Three Months Ended June 30, 2016		Three Months Ended June 30, 2017	
Gains (Losses) Included in AOCL	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Beginning balance	$ (61,107)	$ (4,689)	$ (56,236)	$ (7,681)
Amortization of prior service credit	(45)	(929)	(46)	—
Amortization of actuarial loss	1,107	185	1,783	200
Settlement cost	—	—	361	—
Ending balance	$ (60,045)	$ (5,433)	$ (54,138)	$ (7,481)

	Six Months Ended June 30, 2016		Six Months Ended June 30, 2017	
Gains (Losses) Included in AOCL	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Beginning balance	$ (62,279)	$ (3,945)	$ (58,584)	$ (7,881)
Amortization of prior service credit	(90)	(1,857)	(91)	—
Amortization of actuarial loss	2,324	369	2,811	400
Settlement cost	—	—	1,726	—
Ending balance	$ (60,045)	$ (5,433)	$ (54,138)	$ (7,481)

Contributions estimated to be paid into the plans in 2017 are $26.5 million and $0.3 million for the pension and other postretirement benefit plans, respectively.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Debt

Long-term debt at December 31, 2016 and June 30, 2017 was as follows (in thousands):

	December 31, 2016	June 30, 2017
Commercial paper	$ 50,000	$ 197,000
6.40% Notes due 2018	250,000	250,000
6.55% Notes due 2019	550,000	550,000
4.25% Notes due 2021	550,000	550,000
3.20% Notes due 2025	250,000	250,000
5.00% Notes due 2026	650,000	650,000
6.40% Notes due 2037	250,000	250,000
4.20% Notes due 2042	250,000	250,000
5.15% Notes due 2043	550,000	550,000
4.20% Notes due 2045	250,000	250,000
4.25% Notes due 2046	500,000	500,000
Face value of long-term debt	4,100,000	4,247,000
Unamortized debt issuance costs(1)	(26,948)	(25,677)
Net unamortized debt premium(1)	6,530	4,910
Net unamortized amount of gains from historical fair value hedges(1)	7,610	5,679
Long-term debt, net	$ 4,087,192	$ 4,231,912

(1) Debt issuance costs, note discounts and premiums and realized gains and losses of historical fair value hedges are being amortized or accreted to the applicable notes over the respective lives of those notes.

All of the instruments detailed in the table above are senior indebtedness.

Revolving Credit Facilities. At June 30, 2017, the total borrowing capacity under our revolving credit facility with a maturity date of October 27, 2020 was $1.0 billion. Any borrowings outstanding under this facility are classified as long-term debt on our consolidated balance sheets. Borrowings under this facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.000% to 1.625% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate between 0.100% and 0.275% depending on our credit ratings. The unused commitment fee was 0.125% at June 30, 2017. Borrowings under this facility may be used for general partnership purposes, including capital expenditures. As of both December 31, 2016 and June 30, 2017, there were no borrowings outstanding under this facility, with $6.3 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under this facility.

At June 30, 2017, the total borrowing capacity under our 364-day credit facility was $250.0 million. The maturity date of this credit facility is October 19, 2017. Any borrowings under this facility are classified as current debt on our consolidated balance sheets. Borrowings under this facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.000% to 1.625% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate between 0.080% and 0.225% depending on our credit ratings. The unused commitment fee was 0.100% at June 30, 2017. Borrowings under this facility may be used for general partnership purposes, including capital expenditures. As of both December 31, 2016 and June 30, 2017, there were no borrowings outstanding under this facility.

Commercial Paper Program. We have a commercial paper program under which we may issue commercial paper notes in an amount up to the available capacity under our $1.0 billion revolving credit facility. The maturities of the commercial paper notes vary, but may not exceed 397 days from the date of issuance. Because the commercial paper we can issue is limited to amounts available under our revolving credit facility, amounts outstanding under the program are classified as long-term debt. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. The weighted-average interest rate for commercial paper borrowings based on the number of days outstanding was 0.8% for the year ended December 31, 2016 and 1.2% for the six months ended June 30, 2017.

8. Derivative Financial Instruments

Interest Rate Derivatives

We periodically enter into interest rate derivatives to hedge the fair value of debt or hedge against variability in interest rates, and we have historically designated these derivatives as fair value or cash flow hedges for accounting purposes. Adjustments resulting from discontinued hedges continue to be recognized in accordance with their historic hedging relationships.

We have entered into $100.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2018. The fair values of these contracts at June 30, 2017 were recorded on our balance sheets as other current assets of $12.6 million, with the offset recorded to other comprehensive income. We account for these agreements as cash flow hedges.

Commodity Derivatives

Hedging Strategies

Our butane blending activities produce gasoline, and we can reasonably estimate the timing and quantities of sales of these products. We use a combination of exchange-based commodities futures contracts and forward purchase and sale contracts to help manage commodity price changes and mitigate the risk of decline in the product margin realized from our butane blending activities. Further, certain of our other commercial operations generate petroleum products, and we also use futures contracts to hedge against price changes for some of these commodities.

Forward physical purchase and sale contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The futures contracts that we enter into fall into one of three hedge categories:

Hedge Category	Hedge Purpose	Accounting Treatment
Qualifies For Hedge Accounting Treatment		
Cash Flow Hedge	To hedge the variability in cash flows related to a forecasted transaction.	The effective portion of changes in the fair value of the hedge is recorded to accumulated other comprehensive income/loss and reclassified to earnings when the forecasted transaction occurs. Any ineffectiveness is recognized currently in earnings.
Fair Value Hedge	To hedge against changes in the fair value of a recognized asset or liability.	The effective portion of changes in the fair value of the hedge is recorded as adjustments to the asset or liability being hedged. Any ineffectiveness and amounts excluded from the assessment of hedge effectiveness are recognized currently in earnings.
Does Not Qualify For Hedge Accounting Treatment		
Economic Hedge	To effectively serve as either a fair value or a cash flow hedge; however, the derivative agreement does not qualify for hedge accounting treatment under Accounting Standards Codification ("ASC") 815, *Derivatives and Hedging*.	Changes in the fair value of these agreements are recognized currently in earnings.

During the six months ended June 30, 2016 and 2017, none of the commodity hedging contracts we entered into qualified for or were designated as cash flow hedges.

We use futures contracts designated as economic hedges for accounting purposes to hedge against changes in the price of refined products and crude oil that we expect to sell in the future. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to product sales revenue.

We also use futures contracts designated as economic hedges for accounting purposes to hedge against changes in the price of butane we expect to purchase in the future. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to cost of product sales.

Additionally, we hold certain crude oil tank bottoms which we classify as long-term assets and include with other noncurrent assets on our consolidated balance sheets. We use futures contracts to hedge against changes in the fair value of these assets. We record the effective portion of the gains or losses for those contracts that qualify as fair value hedges as adjustments to the asset being hedged and the ineffective portions as well as amounts excluded from the assessment of hedge effectiveness as adjustments to other (income) or expense.

As outlined in the table below, our open futures contracts at June 30, 2017 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
Futures - Fair Value Hedges	0.7 million barrels of crude oil	November 2017
Futures - Economic Hedges	4.6 million barrels of refined products and crude oil	Between July 2017 and April 2018
Futures - Economic Hedges	1.4 million barrels of butane	Between September 2017 and April 2018

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Energy Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2016, we had made margin deposits of $49.9 million for our future contracts with our counterparties, which were recorded as current assets under energy commodity derivatives deposits on our consolidated balance sheets. At June 30, 2017, we had made margin deposits of $4.5 million for our future contracts with one of our counterparties, which were recorded as current assets under energy commodity derivatives deposits on our consolidated balance sheets. Additionally at June 30, 2017, we had received margin deposits of $0.1 million for our future contracts with a second counterparty, which were recorded as current liabilities under energy commodity derivatives deposits on our consolidated balance sheets.We have the right to offset the combined fair values of our open futures contracts against our margin deposits under a master netting arrangement for each counterparty; however, we have elected to present the combined fair values of our open futures contracts separately from the related margin deposits on our consolidated balance sheets. Additionally, we have the right to offset the fair values of our futures contracts together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets. A schedule of the derivative amounts we have offset and the deposit amounts we could offset under a master netting arrangement are provided below as of December 31, 2016 and June 30, 2017 (in thousands):

	December 31, 2016				
Description	Gross Amounts of Recognized Liabilities	Gross Amounts of Assets Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount(1)
Energy commodity derivatives	$ (36,798)	$ 6,060	$ (30,738)	$ 49,899	$ 19,161

	June 30, 2017				
Description	Gross Amounts of Recognized Assets	Gross Amounts of Liabilities Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount(1)
Energy commodity derivatives	$ 8,058	$ (3,808)	$ 4,250	$ 4,373	$ 8,623

(1) Amount represents the maximum loss we would incur if all of our counterparties failed to perform on their derivative contracts.

Impact of Derivatives on Our Financial Statements

Comprehensive Income

The changes in derivative activity included in AOCL for the three and six months ended June 30, 2016 and 2017 were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Losses Included in AOCL	**2016**	**2017**	**2016**	**2017**
Beginning balance	$ (42,216)	$ (32,741)	$ (30,126)	$ (34,776)
Net gain (loss) on cash flow hedges	(8,631)	(2,802)	(21,109)	(1,507)
Reclassification of net loss on cash flow hedges to income	388	739	776	1,479
Ending balance	$ (50,459)	$ (34,804)	$ (50,459)	$ (34,804)

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Statements

The following tables provide a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2016 and 2017 of derivatives accounted for under ASC 815-30, *Derivatives and Hedging—Cash Flow Hedges*, that were designated as hedging instruments (in thousands):

	Three Months Ended June 30, 2016			
			Amount of Loss Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (8,631)	Interest expense	$ (388)	$ —

	Three Months Ended June 30, 2017			
			Amount of Loss Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (2,802)	Interest expense	$ (739)	$ —

	Six Months Ended June 30, 2016			
			Amount of Loss Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (21,109)	Interest expense	$ (776)	$ —

	Six Months Ended June 30, 2017			
			Amount of Loss Reclassified from AOCL into Income	
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Effective Portion	Ineffective Portion
Interest rate contracts	$ (1,507)	Interest expense	$ (1,479)	$ —

As of June 30, 2017, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $3.0 million.

We use futures contracts designated as fair value hedges under ASC 815-25, *Derivatives and Hedging–Fair Value Hedges*, to hedge against changes in the fair value of 0.7 million barrels of crude oil that are contractually reserved as tank bottoms and included with other noncurrent assets on our consolidated balance sheets. The effective portions of the fair value gains or losses on these futures contracts were offset by fair value gains or losses on the tank bottoms. There was no ineffectiveness recognized on these hedges. The cash flows from settled contracts were recorded in operating activities in our consolidated statements of cash flows. The gains (losses) on these futures contracts and the underlying tank bottoms were as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017
Gain (loss) recognized in other income/expense on derivatives (futures contracts)	(7.7)	3.4	(6.2)	6.8
Loss (gain) recognized in other income/expense on hedged item (tank bottoms)	7.7	(3.4)	6.2	(6.8)

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The differential between the current spot price and forward price is excluded from the assessment of hedge effectiveness for these fair value hedges. For the three months ended June 30, 2016 and 2017, we recognized a gain of $1.9 million and $0.3 million, respectively, and for the six months ended June 30, 2016 and 2017, we recognized a gain of $4.2 million and $1.7 million, respectively, for the amounts we excluded from the assessment of effectiveness of these fair value hedges, which we reported as other (income) expense on our consolidated statements of income.

The following table provides a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2016 and 2017 of derivatives accounted for under ASC 815, *Derivatives and Hedging*, that were not designated as hedging instruments (in thousands):

		Amount of Gain (Loss) Recognized on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivatives	2016	2017	2016	2017
Futures contracts	Product sales revenue	$ (11,770)	$ 14,214	$ 4,212	$ 42,894
Futures contracts	Operating expenses	(8,003)	—	(5,404)	—
Futures contracts	Cost of product sales	3,240	(1,184)	2,812	53
	Total	$ (16,533)	$ 13,030	$ 1,620	$ 42,947

The impact of the derivatives in the above table was reflected as cash from operations on our consolidated statements of cash flows.

Balance Sheets

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging,* which are presented on a net basis in our consolidated balance sheets, that were designated as hedging instruments as of December 31, 2016 and June 30, 2017 (in thousands):

	December 31, 2016			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ —	Energy commodity derivatives contracts, net	$ 3,079
Interest rate contracts	Other noncurrent assets	14,114	Other noncurrent liabilities	—
	Total	$ 14,114	Total	$ 3,079

	June 30, 2017			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 3,738	Energy commodity derivatives contracts, net	$ —
Interest rate contracts	Other current assets	12,607	Other current liabilities	—
	Total	$ 16,345	Total	$ —

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging,* which are presented on a net basis in our consolidated balance sheets, that were not designated as hedging instruments as of December 31, 2016 and June 30, 2017 (in thousands):

	December 31, 2016			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 6,060	Energy commodity derivatives contracts, net	$ 33,719

	June 30, 2017			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 4,320	Energy commodity derivatives contracts, net	$ 3,808

9. Commitments and Contingencies

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $24.0 million and $18.9 million at December 31, 2016 and June 30, 2017, respectively. We have classified environmental liabilities as current or noncurrent based on management's estimates regarding the timing of actual payments. Environmental expenses recognized as a result of changes in our environmental liabilities are generally included in operating expenses on our consolidated statements of income. Environmental expenses were $0.8 million and $0.2 million for the three months ended June 30, 2016 and 2017, respectively, and $4.3 million and $4.5 million for the six months ended June 30, 2016 and 2017, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters were $4.1 million at December 31, 2016, of which $0.6 million and $3.5 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Receivables from insurance carriers and other third parties related to environmental matters were $3.9 million at June 30, 2017, of which $0.5 million and $3.4 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets.

Other

See Note 4 – *Investments in Non-Controlled Entities* for detail of our guarantee on behalf of Powder Springs.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our results of operations, financial position or cash flows.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Long-Term Incentive Plan

We have a long-term incentive plan ("LTIP") for certain of our employees and directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate payout of 11.9 million of our limited partner units. The compensation committee of our general partner's board of directors administers our LTIP. The estimated units remaining available under the LTIP at June 30, 2017 total 2.6 million.

Our equity-based incentive compensation expense was as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017
Performance-based awards:				
2014 awards	$ 979	$ —	$ 4,388	$ 28
2015 awards	926	2,066	2,471	3,224
2016 awards	1,023	2,592	2,143	3,641
2017 awards	—	1,252	—	2,498
Time-based awards	481	660	1,057	1,326
Total	$ 3,409	$ 6,570	$ 10,059	$ 10,717
Allocation of LTIP expense on our consolidated statements of income:				
G&A expense	$ 3,378	$ 6,514	$ 9,986	$ 10,632
Operating expense	31	56	73	85
Total	$ 3,409	$ 6,570	$ 10,059	$ 10,717

On February 2, 2017, 207,445 phantom unit awards were issued pursuant to our LTIP. These grants included both performance-based and time-based phantom unit awards and have a three-year vesting period that will end on December 31, 2019.

Basic and Diluted Net Income Per Limited Partner Unit

The difference between our actual limited partner units outstanding and our weighted-average number of limited partner units outstanding used to calculate basic net income per unit is due to the impact of: (i) the phantom units issued to non-employee directors and (ii) the weighted average effect of units actually issued during a period. The difference between the weighted-average number of limited partner units outstanding used for basic and diluted net income per unit calculations on our consolidated statements of income is primarily the dilutive effect of phantom unit grants associated with our LTIP that have not yet vested.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Partners' Capital and Distributions

Partners' Capital

In May 2017, we filed a prospectus supplement to the shelf registration statement for our continuous equity offering program (which we refer to as an at-the-market program, or "ATM") pursuant to which we may issue up to $750.0 million of common units in amounts, at prices and on terms to be determined by market conditions at the time. The net proceeds from any sales under the ATM, after deducting the sales agents' commissions and our offering expenses, will be used for general partnership purposes, including repayment of indebtedness or capital expenditures. No units were issued pursuant to this program during the current period.

The following table details the changes in the number of our limited partner units outstanding from January 1, 2017 through June 30, 2017:

Limited partner units outstanding on January 1, 2017	**227,783,916**
January 2017–Settlement of 2014 awards(a)	216,679
During 2017–Other(b)	23,961
Limited partner units outstanding on June 30, 2017	**228,024,556**

(a) Limited partner units issued to settle long-term incentive plan awards to certain employees that vested on December 31, 2016.
(b) Limited partner units issued to settle the equity-based retainers paid to certain independent directors of our general partner and the final payment of deferred director compensation to a former director.

Distributions

Distributions we paid during 2016 and 2017 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
02/12/2016	$ 0.7850	$ 178,808
05/13/2016	0.8025	182,797
Through 06/30/2016	1.5875	361,605
08/12/2016	0.8200	186,783
11/14/2016	0.8375	190,769
Total	$ 3.2450	$ 739,157
02/14/2017	$ 0.8550	$ 194,961
05/15/2017	0.8725	198,951
Through 06/30/2017	1.7275	393,912
08/14/2017(a)	0.8900	202,942
Total	$ 2.6175	$ 596,854

(a) Our general partner's board of directors declared this cash distribution in July 2017 to be paid on August 14, 2017 to unitholders of record at the close of business on July 31, 2017.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Fair Value

Fair Value Methods and Assumptions - Financial Assets and Liabilities.

We used the following methods and assumptions in estimating fair value of our financial assets and liabilities:

- *Energy commodity derivatives contracts*. These include exchange-traded futures contracts related to petroleum products. These contracts are carried at fair value on our consolidated balance sheets and are valued based on quoted prices in active markets. See Note 8 – *Derivative Financial Instruments* for further disclosures regarding these contracts.

- *Interest rate contracts.* These include forward-starting interest rate swap agreements to hedge against the risk of variability of interest payments on future debt. These contracts are carried at fair value on our consolidated balance sheets and are valued based on an assumed exchange, at the end of each period, in an orderly transaction with a market participant in the market in which the financial instrument is traded. The exchange value was calculated using present value techniques on estimated future cash flows based on forward interest rate curves. See Note 8 – *Derivative Financial Instruments* for further disclosures regarding these contracts.

- *Long-term receivables.* These primarily include payments receivable under a direct-financing leasing arrangement and cost reimbursement payments receivable. These receivables were recorded at fair value on our consolidated balance sheets, using then-current market rates to estimate the present value of future cash flows.

- *Debt.* The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2016 and June 30, 2017; however, where recent observable market trades were not available, prices were determined using adjustments to the last traded value for that debt issuance or by adjustments to the prices of similar debt instruments of peer entities that are actively traded. The carrying amount of borrowings, if any, under our revolving credit facility and our commercial paper program approximates fair value due to the frequent repricing of these obligations.

Fair Value Measurements - Financial Assets and Liabilities

The following tables summarize the carrying amounts, fair values and fair value measurements recorded or disclosed as of December 31, 2016 and June 30, 2017 based on the three levels established by ASC 820, *Fair Value Measurements and Disclosures* (in thousands):

	December 31, 2016				
			Fair Value Measurements using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts	$ (30,738)	$ (30,738)	$ (30,738)	$ —	$ —
Interest rate contracts	$ 14,114	$ 14,114	$ —	$ 14,114	$ —
Long-term receivables	$ 23,870	$ 23,870	$ —	$ —	$ 23,870
Debt	$ (4,087,192)	$ (4,262,321)	$ —	$ (4,262,321)	$ —

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	June 30, 2017				
			Fair Value Measurements using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts	$ 4,250	$ 4,250	$ 4,250	$ —	$ —
Interest rate contracts	$ 12,607	$ 12,607	$ —	$ 12,607	$ —
Long-term receivables	$ 22,532	$ 22,532	$ —	$ —	$ 22,532
Debt	$ (4,231,912)	$ (4,483,046)	$ —	$ (4,483,046)	$ —

13. Related Party Transactions

Stacy P. Methvin is an independent member of our general partner's board of directors and is also a director of one of our customers. We received tariff revenue from this customer of $4.7 million and $4.3 million for the three months ended June 30, 2016 and 2017, respectively, and $7.7 million and $8.4 million for the six months ended June 30, 2016 and 2017, respectively. We recorded receivables of $1.4 million from this customer at both December 31, 2016 and June 30, 2017. The tariff revenue we recognized from this customer was in the normal course of business, with rates determined in accordance with published tariffs.

See Note 4 – *Investments in Non-Controlled Entities* for a discussion of transactions with our joint ventures.

14. Subsequent Events

Recognizable events

No recognizable events occurred subsequent to June 30, 2017.

Non-recognizable events

Cash Distribution. In July 2017, our general partner's board of directors declared a quarterly distribution of $0.89 per unit to be paid on August 14, 2017 to unitholders of record at the close of business on July 31, 2017. The total cash distributions expected to be paid under this declaration are approximately $202.9 million.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

We are a publicly traded limited partnership principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of June 30, 2017, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, our condensate splitter and storage facilities with an aggregate storage capacity of approximately 27 million barrels, of which approximately 17 million barrels are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our partnership. The following discussion and analysis should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes and (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2016.

Recent Developments

Cash Distribution. In July 2017, the board of directors of our general partner declared a quarterly cash distribution of $0.89 per unit for the period of April 1, 2017 through June 30, 2017. This quarterly cash distribution will be paid on August 14, 2017 to unitholders of record on July 31, 2017. Total distributions expected to be paid under this declaration are approximately $202.9 million.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expense, which management does not focus on when evaluating the core profitability of our separate operating segments. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales revenue and cost of product sales are determined in accordance with GAAP. Our butane blending, fractionation and other commodity-related activities generate significant revenue. However, we believe the product margin from these activities, which takes into account the related cost of product sales, better represents its importance to our results of operations.

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

	Three Months Ended June 30,		Variance Favorable (Unfavorable)	
	2016	2017	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$ 247.8	$ 277.9	$ 30.1	12
Crude oil	101.4	108.4	7.0	7
Marine storage	43.0	47.8	4.8	11
Intersegment eliminations	—	(0.9)	(0.9)	n/a
Total transportation and terminals revenue	392.2	433.2	41.0	10
Affiliate management fee revenue	2.9	4.2	1.3	45
Operating expenses:				
Refined products	98.5	100.7	(2.2)	(2)
Crude oil	20.5	31.4	(10.9)	(53)
Marine storage	16.3	15.3	1.0	6
Intersegment eliminations	(1.1)	(2.1)	1.0	91
Total operating expenses	134.2	145.3	(11.1)	(8)
Product margin:				
Product sales revenue	123.8	182.0	58.2	47
Cost of product sales	95.7	145.9	(50.2)	(52)
Product margin	28.1	36.1	8.0	28
Earnings of non-controlled entities	15.4	25.5	10.1	66
Operating margin	304.4	353.7	49.3	16
Depreciation and amortization expense	43.3	48.9	(5.6)	(13)
G&A expense	34.6	43.4	(8.8)	(25)
Operating profit	226.5	261.4	34.9	15
Interest expense (net of interest income and interest capitalized)	41.2	48.1	(6.9)	(17)
Gain on exchange of interest in non-controlled entity	(1.2)	—	(1.2)	(100)
Other expense (income)	(2.0)	2.0	(4.0)	n/a
Income before provision for income taxes	188.5	211.3	22.8	12
Provision for income taxes	0.7	0.9	(0.2)	(29)
Net income	$ 187.8	$ 210.4	$ 22.6	12
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$ 1.427	$ 1.481		
Volume shipped (million barrels):				
Gasoline	71.1	76.7		
Distillates	36.4	40.7		
Aviation fuel	6.9	7.6		
Liquefied petroleum gases	4.2	4.6		
Total volume shipped	118.6	129.6		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$ 1.360	$ 1.380		
Volume shipped (million barrels)	45.1	47.3		
Crude oil terminal average utilization (million barrels per month)	14.7	15.2		
Select joint venture pipelines:				
BridgeTex - volume shipped (million barrels)(1)	19.3	21.8		
Saddlehorn - volume shipped (million barrels)(2)	—	3.7		
Marine storage:				
Marine terminal average utilization (million barrels per month)	23.0	23.9		

(1) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.
(2) These volumes reflect the total shipments for the Saddlehorn pipeline, which began operations in September 2016 and is owned 40% by us.

Transportation and terminals revenue increased $41.0 million resulting from:

- an increase in refined products revenue of $30.1 million. Shipments increased in the current period primarily due to volumes from recent growth projects, including our Little Rock pipeline extension, which commenced commercial operations in July 2016, and stronger demand for refined products in large part due to higher distillate demand in crude oil production regions. The average rate per barrel in the current period was favorably impacted by the mid-year 2016 tariff adjustment, which was an approximate 2% average increase. Additionally, revenue from storage and other ancillary services along our pipeline system increased due to increased customer activity;
- an increase in crude oil revenue of $7.0 million primarily due to contributions from our new condensate splitter at Corpus Christi that began commercial operations in June 2017, and higher deficiency revenue for volume committed but not moved on our Houston distribution system; and
- an increase in marine storage revenue of $4.8 million primarily due to increased storage utilization, higher storage rates and additional ancillary fees reflecting increased customer activities at our marine facilities.

Operating expenses increased by $11.1 million primarily resulting from:

- an increase in refined products expenses of $2.2 million primarily due to higher asset integrity spending related to the timing of maintenance work and rental costs for a pipeline segment we began leasing in third quarter 2016 in connection with our Little Rock pipeline, partially offset by more favorable product overages (which reduce operating expenses);
- an increase in crude oil expenses of $10.9 million primarily due to higher compensation and other costs associated with our new condensate splitter that began commercial operations in June 2017 and less favorable product overages; and
- a decrease in marine storage expenses of $1.0 million primarily due to favorable product overages.

Product sales revenue resulted primarily from our butane blending activities, transmix fractionation, tender deducts and the sale of product gains from our operations. We utilize futures contracts to hedge against changes in the price of petroleum products we expect to sell in future periods, as well as to hedge against changes in the price of butane we expect to purchase. See Note 8 – *Derivative Financial Instruments* in Item 1 of Part I for a discussion of our hedging strategies and how our use of futures contracts impacts our product margin. Product margin increased $8.0 million primarily due to recognition of gains on futures contracts in the current period compared to losses in the prior period, partially offset by higher butane costs, resulting in compressed butane blending margins. See *Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations* below for more information about our futures contracts.

Earnings of non-controlled entities increased $10.1 million primarily due to increased earnings from BridgeTex Pipeline Company, LLC ("BridgeTex") mainly attributable to incremental spot shipments (including spot shipments by us; see Note 4 – *Investments in Non-Controlled Entities* for information about spot shipments that we made on the BridgeTex pipeline in second quarter 2017), as well as additional shipments from BridgeTex's new Eaglebine origin, and earnings from Saddlehorn Pipeline Company, LLC ("Saddlehorn"), which began operating during third quarter 2016.

Depreciation and amortization expense increased $5.6 million primarily due to commencement of depreciation of expansion capital projects recently placed into service.

G&A expense increased $8.8 million primarily due to higher compensation costs resulting from an increase in employee headcount mainly as a result of expansion projects and higher equity-based compensation expense due to timing of accrual adjustments.

Interest expense, net of interest income and interest capitalized, increased $6.9 million in second quarter 2017, primarily due to lower capitalized interest and higher outstanding debt in the current period. Our average outstanding debt increased from $3.8 billion in second quarter 2016 to $4.3 billion in second quarter 2017 primarily due to borrowings for expansion capital expenditures. Our weighted-average interest rate of 4.7% in second quarter 2017 was lower than the 4.9% rate incurred in second quarter 2016.

In second quarter 2016, we recognized an additional $1.2 million gain related to the transfer in first quarter 2016 of our 50% membership interest in Osage Pipe Line Company, LLC ("Osage"). See Note 4 – *Investments in Non-Controlled Entities* of the consolidated financial statements included in Item 1 of this report for more details regarding this transaction.

Other expense (income) was $4.0 million unfavorable due to higher costs related to pension settlements in the current period and a less favorable non-cash adjustment in second quarter 2017 for the change in the differential between the current spot price and forward price on fair value hedges associated with our crude oil tank bottoms.

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

	Six Months Ended June 30,		Variance Favorable (Unfavorable)	
	2016	2017	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$ 472.6	$ 519.8	$ 47.2	10
Crude oil	203.1	213.5	10.4	5
Marine storage	86.6	94.2	7.6	9
Intersegment eliminations	—	(1.6)	(1.6)	n/a
Total transportation and terminals revenue	762.3	825.9	63.6	8
Affiliate management fee revenue	6.1	8.0	1.9	31
Operating expenses:				
Refined products	184.3	194.2	(9.9)	(5)
Crude oil	41.6	58.8	(17.2)	(41)
Marine storage	33.5	28.0	5.5	16
Intersegment eliminations	(2.3)	(4.1)	1.8	78
Total operating expenses	257.1	276.9	(19.8)	(8)
Product margin:				
Product sales revenue	270.3	427.6	157.3	58
Cost of product sales	209.3	318.8	(109.5)	(52)
Product margin	61.0	108.8	47.8	78
Earnings of non-controlled entities	33.0	47.0	14.0	42
Operating margin	605.3	712.8	107.5	18
Depreciation and amortization expense	87.1	96.2	(9.1)	(10)
G&A expense	75.2	83.7	(8.5)	(11)
Operating profit	443.0	532.9	89.9	20
Interest expense (net of interest income and interest capitalized)	78.4	94.8	(16.4)	(21)
Gain on exchange of interest in non-controlled entity	(28.1)	—	(28.1)	(100)
Other expense (income)	(3.8)	3.2	(7.0)	n/a
Income before provision for income taxes	396.5	434.9	38.4	10
Provision for income taxes	1.6	1.8	(0.2)	(13)
Net income	$ 394.9	$ 433.1	$ 38.2	10
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$ 1.422	$ 1.472		
Volume shipped (million barrels):				
Gasoline	132.2	142.9		
Distillates	72.7	78.6		
Aviation fuel	12.4	13.5		
Liquefied petroleum gases	5.8	5.7		
Total volume shipped	223.1	240.7		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$ 1.403	$ 1.456		
Volume shipped (million barrels)	88.8	88.6		
Crude oil terminal average utilization (million barrels per month)	14.6	15.9		
Select joint venture pipelines:				
BridgeTex - volume shipped (million barrels)(1)	38.1	40.7		
Saddlehorn - volume shipped (million barrels)(2)	—	7.7		
Marine storage:				
Marine terminal average utilization (million barrels per month)	23.2	24.0		

(1) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.
(2) These volumes reflect the total shipments for the Saddlehorn pipeline, which began operations in September 2016 and is owned 40% by us.

Transportation and terminals revenue increased $63.6 million resulting from:

- an increase in refined products revenue of $47.2 million. Shipments increased in the current period primarily due to volumes from recent growth projects, including our Little Rock pipeline extension which commenced commercial operations in July 2016, and stronger demand for refined products. The average rate per barrel in the current period was favorably impacted by the mid-year 2016 tariff adjustment, which was an approximate 2% average increase. Additionally, revenue from storage and other ancillary services along our pipeline system increased due to increased customer activity;
- an increase in crude oil revenue of $10.4 million primarily due to contributions from our new condensate splitter at Corpus Christi that began commercial operations in June 2017, and higher deficiency revenue for volume committed but not moved on our Houston distribution system; and
- an increase in marine storage revenue of $7.6 million primarily due to increased storage utilization, higher storage rates and additional ancillary fees reflecting increased customer activities at our marine facilities.

Operating expenses increased by $19.8 million primarily resulting from:

- an increase in refined products expenses of $9.9 million primarily due to higher asset integrity spending related to the timing of maintenance work, rental costs for a pipeline segment we began leasing in third quarter 2016 in connection with our Little Rock pipeline and higher compensation costs, partially offset by more favorable product overages (which reduce operating expenses);
- an increase in crude oil expenses of $17.2 million primarily due to less favorable product overages, higher compensation and other costs associated with our new condensate splitter that began commercial operations in June 2017 and more asset integrity spending during the current year; and
- a decrease in marine storage expenses of $5.5 million primarily due to favorable product overages.

Product margin increased $47.8 million primarily due to recognition of gains on futures contracts in the current period compared to losses in the prior period, partially offset by lower margins on product sales. See *Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations* below for more information about our futures contracts.

Earnings of non-controlled entities increased $14.0 million primarily due to earnings from Saddlehorn, which began operating during third quarter 2016. Additionally, earnings from BridgeTex were higher mainly attributable to incremental spot shipments (including spot shipments by us; see Note 4 - Investments in Non-Controlled Entities for information about spot shipments that we made on the BridgeTex pipeline in second quarter 2017), as well as additional shipments from BridgeTex's new Eaglebine origin.

Depreciation and amortization expense increased $9.1 million primarily due to commencement of depreciation of expansion capital projects recently placed into service.

G&A expense increased $8.5 million primarily due to higher compensation costs resulting from an increase in employee headcount mainly as a result of expansion projects.

Interest expense, net of interest income and interest capitalized, increased $16.4 million in 2017, primarily due to higher outstanding debt and lower capitalized interest in the current period. Our average outstanding debt increased from $3.8 billion in 2016 to $4.2 billion in 2017 primarily due to borrowings for expansion capital expenditures. Our weighted-average interest rate of 4.7% in 2017 was slightly lower than the 4.8% rate incurred in 2016.

In 2016, we recognized a $28.1 million non-cash gain related to the transfer of our 50% membership interest in Osage. See Note 4 – *Investments in Non-Controlled Entities* of the consolidated financial statements included in Item 1 of this report for more details regarding this transaction.

Other expense (income) was $7.0 million unfavorable due to higher costs related to pension settlements in the current period and a less favorable non-cash adjustment in 2017 for the change in the differential between the current spot price and forward price on fair value hedges associated with our crude oil tank bottoms.

Distributable Cash Flow

We calculate the non-GAAP measures of distributable cash flow ("DCF") and adjusted EBITDA in the table below. Management uses DCF as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid to our limited partners each period. Management also uses DCF as a basis for determining the payouts for the performance-based awards issued under our equity-based compensation plan. Adjusted EBITDA is an important measure that we and the investment community use to assess the financial results of an entity. We believe that investors benefit from having access to the same financial measures utilized by management for these evaluations. A reconciliation of DCF and adjusted EBITDA for the six months ended June 30, 2016 and 2017 to net income, which is its nearest comparable GAAP financial measure, follows (in millions):

	Six Months Ended June 30,		Increase
	2016	2017	(Decrease)
Net income	$ 394.9	$ 433.1	$ 38.2
Interest expense, net	78.4	94.8	16.4
Depreciation and amortization	87.1	96.2	9.1
Equity-based incentive compensation(1)	(4.3)	(3.2)	1.1
Loss on sale and retirement of assets	3.3	5.3	2.0
Gain on exchange of interest in non-controlled entity(2)	(28.1)	—	28.1
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions(4)	(5.7)	(7.3)	(1.6)
Derivative gains (losses) recognized in previous periods associated with product sales completed in the period(4)	36.2	(25.5)	(61.7)
Lower-of-cost-or-market adjustments(5)	(1.7)	4.9	6.6
Total commodity-related adjustments	28.8	(27.9)	(56.7)
Cash distributions received from non-controlled entities in excess of earnings	0.1	10.9	10.8
Other(3)	2.5	3.0	0.5
Adjusted EBITDA	562.7	612.2	49.5
Interest expense, net, excluding debt issuance cost amortization	(76.9)	(93.2)	(16.3)
Maintenance capital(6)	(59.4)	(41.1)	18.3
DCF	$ 426.4	$ 477.9	$ 51.5

(1) Because we intend to satisfy vesting of unit awards under our equity-based incentive compensation plan with the issuance of limited partner units, expenses related to this plan generally are deemed non-cash and added back for DCF purposes. Total equity-based incentive compensation expense for the six months ended June 30, 2016 and 2017 was $10.1 million and $10.7 million, respectively. However, the figures above include adjustments of $14.4 million and $13.9 million, respectively, for cash payments associated with our equity-based incentive compensation plan, which primarily include tax withholdings.

(2) In February 2016, we transferred our 50% membership interest in Osage to an affiliate of HollyFrontier Corporation ("HFC"). In conjunction with this transaction, we entered into several commercial agreements with affiliates of HFC, which were recorded as intangible assets and other receivables on our consolidated balance sheets. We recorded a $28.1 million non-cash gain in relation to this transaction.

(3) In conjunction with the February 2016 Osage transaction, HFC agreed to make certain payments to us until HFC completes a connection to our El Paso terminal. These payments replace distributions we would have received had the Osage transaction not occurred and are, therefore, included in our calculation of DCF.

(4) Certain derivatives we use as economic hedges have not been designated as hedges for accounting purposes and the mark-to-market changes of these derivatives are recognized currently in earnings. In addition, we have designated certain derivatives we use to hedge our crude oil tank bottoms as fair value hedges and the change in the differential between the current spot price and forward price on these hedges is recognized currently in earnings. We exclude the net impact of both of these adjustments from our determination of

DCF until the hedged products are physically sold. In the period in which these hedged products are physically sold, the net impact of the associated hedges is included in our determination of DCF.

(5) We add the amount of lower-of-cost-or-market ("LCM") adjustments on inventory and firm purchase commitments we recognize in each applicable period to determine DCF as these are non-cash charges against income. In subsequent periods when we physically sell or purchase the related products, we deduct the LCM adjustments previously recognized to determine DCF.

(6) Maintenance capital expenditures maintain our existing assets and do not generate incremental DCF (i.e. incremental returns to our unitholders). For this reason, we deduct maintenance capital expenditures to determine DCF.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Operating Activities. Operating cash flows consist of net income adjusted for certain non-cash items and changes in certain assets and liabilities.

Net cash provided by operating activities was $407.1 million and $572.4 million for the six months ended June 30, 2016 and 2017, respectively. The $165.3 million increase in 2017 was due to changes in our working capital, adjustments for non-cash items and higher net income as previously described.

Investing Activities. Investing cash flows consist primarily of capital expenditures and investments in non-controlled entities.

Net cash used by investing activities for the six months ended June 30, 2016 and 2017 was $413.4 million and $320.7 million, respectively. During 2017, we incurred $289.6 million for capital expenditures, which included $41.1 million for maintenance capital and $248.5 million for expansion capital. Also during the 2017 period, we contributed capital of $55.3 million in conjunction with our joint venture capital projects, which we account for as investments in non-controlled entities. During 2016, we incurred $321.1 million for capital expenditures, which included $59.4 million for maintenance capital and $261.7 million for expansion capital. Also during the 2016 period, we contributed capital of $109.9 million in conjunction with our joint venture capital projects.

Financing Activities. Financing cash flows consist primarily of distributions to our unitholders and borrowings and repayments under long-term notes and our commercial paper program.

Net cash provided by financing activities for the six months ended June 30, 2016 was $11.8 million, and net cash used by financing activities for the six months ended June 30, 2017 was $260.9 million. During 2017, we have paid cash distributions of $393.9 million to our unitholders. Additionally, net commercial paper borrowings during the 2017 period were $146.9 million. Also, in January 2017, the cumulative amounts of the 2014 equity-based incentive compensation awards were settled by issuing 216,679 limited partner units and distributing those units to the long-term incentive plan ("LTIP") participants, resulting in payments primarily associated with tax withholdings of $13.9 million. During 2016, we paid cash distributions of $361.6 million to our unitholders. Additionally, we received net proceeds of $649.2 million from borrowings under long-term notes, which were used in part to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital. Also, in February 2016, the cumulative amounts of the 2013 equity-based incentive compensation awards were settled by issuing 350,552 limited partner units and distributing those units to the LTIP participants, resulting in payments of associated tax withholdings of $14.4 million.

The quarterly distribution amount related to our second quarter 2017 financial results (to be paid in third quarter 2017) is $0.89 per unit. If we are able to meet management's targeted distribution growth of 8% for 2017 and the number of outstanding limited partner units remains at 228.0 million, total cash distributions of approximately $818 million will be paid to our unitholders related to 2017 earnings. Management believes we will have sufficient DCF to fund these distributions.

Capital Requirements

Our businesses require continual investments to maintain, upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending consists primarily of:

- Maintenance capital expenditures. These expenditures include costs required to maintain equipment reliability and safety and to address environmental or other regulatory requirements rather than to generate incremental DCF; and
- Expansion capital expenditures. These expenditures are undertaken primarily to generate incremental DCF and include costs to acquire additional assets to grow our business and to expand or upgrade our existing facilities, which we refer to as organic growth projects. Organic growth projects include, for example, capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

For the six months ended June 30, 2017, our maintenance capital spending was $41.1 million. For 2017, we expect to spend approximately $90 million on maintenance capital.

During the first six months of 2017, we spent $248.5 million for organic growth capital and contributed $55.3 million for capital projects in conjunction with our joint ventures. Based on the progress of expansion projects already underway, we expect to spend approximately $600 million for expansion capital during 2017, with an additional $400 million in 2018 to complete our current projects.

Liquidity

Cash generated from operations is our primary source of liquidity for funding debt service, maintenance capital expenditures and quarterly distributions to our unitholders. Additional liquidity for purposes other than quarterly distributions, such as expansion capital expenditures and debt repayments, is available through borrowings under our commercial paper program and revolving credit facilities, as well as from other borrowings or issuances of debt or limited partner units (see Note 7 – *Debt* and Note 11 – *Partners' Capital and Distributions* of the consolidated financial statements included in Item 1 of Part I of this report for detail of our borrowings and changes in partners' capital). If capital markets do not permit us to issue additional debt and equity securities, our business may be adversely affected, and we may not be able to acquire additional assets and businesses, fund organic growth projects or continue paying cash distributions at the current level.

Off-Balance Sheet Arrangements

None.

Environmental

Our operations are subject to federal, state and local environmental laws and regulations. We have accrued liabilities for estimated costs at our facilities and properties. We record liabilities when environmental costs are probable and can be reasonably estimated. The determination of amounts recorded for environmental liabilities involves significant judgments and assumptions by management. Due to the inherent uncertainties involved in determining environmental liabilities, it is reasonably possible that the actual amounts required to extinguish these liabilities could be materially different from those we have recognized.

Other Items

Pipeline Tariff Changes. The Federal Energy Regulatory Commission (“FERC”) regulates the rates charged on interstate common carrier pipeline operations primarily through an indexing methodology, which establishes the maximum amount by which tariffs can be adjusted each year. Approximately 40% of our refined products tariffs are subject to this indexing methodology while the remaining 60% of our refined products tariffs are either subject to regulations by the states in which we operate or are deemed competitive by the FERC, in which case these rates can be adjusted at our discretion based on market factors. The FERC-approved indexing method to be used for the five-year period beginning in July 2016 is the annual change in the producer price index for finished goods (“PPI-FG”) plus 1.23%. The change in PPI-FG for 2016 was a reduction of approximately 1%. As a result, we increased our rates by approximately 0.2% in the 40% of our markets that are subject to the FERC’s index methodology on July 1, 2017. In the 60% of our markets that are deemed competitive, we increased our rates by an average of approximately 4% on July 1, 2017.

Senior Management Changes. Melanie Little was elected by our general partner’s board of directors as Senior Vice President, Operations, effective July 1, 2017. Ms. Little has 16 years of service with us and has held Vice President level positions for the last six years in Crude Oil Commercial and Operations.

Commodity Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities, which exposes us to commodity price risk. We use forward physical commodity contracts and exchange-based futures contracts to help manage this commodity price risk. We use forward physical contracts to purchase butane and sell refined products. We account for these forward physical contracts as normal purchase and sale contracts, using traditional accrual accounting. We use futures contracts to hedge against changes in prices of refined products and crude oil that we expect to sell and of butane that we expect to purchase in future periods. We use and account for those futures contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those futures contracts that do not qualify for hedge accounting treatment as economic hedges.

As of and for the six months ended June 30, 2017, our open derivative contracts and the impact of the derivatives we settled during the period were as follows:

- Futures contracts to hedge against future price changes of certain crude oil tank bottoms, which we account for as fair value hedges. The cumulative amount of gains from these agreements was recorded as an adjustment to the asset being hedged, and there has been no ineffectiveness recognized for these hedges. We exclude the differential between the current spot price and forward price from our assessment of hedge effectiveness for these fair value hedges, and we recognize the net change in this excluded amount as other income on our consolidated statements of income.

- Futures contracts used to hedge sales and purchases of refined products, crude oil and butane related to our tender deductions, product overages, butane blending, fractionation and certain crude oil inventory activities. These contracts were accounted for as economic hedges, with the change in fair value of contracts that hedge future sales recorded to product sales, and the change in fair value of contracts that hedge future purchases recorded to cost of product sales.

For further information regarding the quantities of refined products and crude oil hedged at June 30, 2017 and the fair value of open hedge contracts at that date, please see *Item 3. Quantitative and Qualitative Disclosures about Market Risk*.

The following tables provide a summary of the impacts of the mark-to-market gains and losses associated with these futures contracts on our results of operations for the respective periods presented (in millions):

	Six Months Ended June 30, 2016				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Net Income
Gains (losses) recorded on open futures contracts during the period	$ (4.6)	$ 2.9	$ 1.2	$ 4.2	$ 3.7
Gains (losses) recognized on settled futures contracts during the period	8.8	(0.1)	(6.6)	—	2.1
Net impact of futures contracts	$ 4.2	$ 2.8	$ (5.4)	$ 4.2	$ 5.8

	Six Months Ended June 30, 2017				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Net Income
Gains (losses) recorded on open futures contracts during the period	$ 1.8	$ (1.3)	$ —	$ 1.7	$ 2.2
Gains recognized on settled futures contracts during the period	41.1	1.4	—	—	42.5
Net impact of futures contracts	$ 42.9	$ 0.1	$ —	$ 1.7	$ 44.7

Related Party Transactions. See Note 13 – *Related Party Transactions* in Item 1 of Part I of this report for detail of our related party transactions.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may be exposed to market risk through changes in commodity prices and interest rates and have established policies to monitor and control these market risks. We use derivative agreements to help manage our exposure to commodity price and interest rate risks.

Commodity Price Risk

Our commodity price risk primarily arises from our butane blending and fractionation activities, and from managing product overages associated with our refined products and crude oil pipelines and certain tank bottoms. We use derivatives such as forward physical contracts and exchange-traded futures contracts to help us manage commodity price risk.

Forward physical contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of June 30, 2017, we had commitments under forward purchase and sale contracts as follows (in millions):

	Total	< 1 Year	1 - 4 Years
Forward purchase contracts – notional value	$ 128.9	$ 67.9	$ 61.0
Forward purchase contracts – barrels	3.7	1.9	1.8
Forward sales contracts – notional value	$ 18.0	$ 18.0	$ —
Forward sales contracts – barrels	0.3	0.3	—

We use futures contracts to hedge against changes in the price of petroleum products we expect to sell or purchase. At June 30, 2017, the fair value of our open futures contracts, representing 5.3 million barrels of petroleum products we expect to sell and 1.4 million barrels of butane we expect to purchase, was a net asset of $4.3 million. Contracts representing 0.7 million barrels of petroleum products we expect to sell qualified for hedge accounting treatment, and we designated and accounted for these contracts as fair value hedges. The remaining contracts did not qualify for hedge accounting treatment under ASC 815, *Derivatives and Hedging*, and we accounted for these contracts as economic hedges, with changes in fair value recognized currently in earnings. With respect to these contracts, a $10.00 per barrel increase (decrease) in the prices of petroleum products related to the contracts representing 4.6 million barrels we expect to sell would result in a $46.0 million decrease (increase) in our operating profit, while a $10.00 per barrel increase (decrease) in the price of butane would result in $14.0 million increase (decrease) in our operating profit. These increases or decreases in operating profit would be substantially offset by higher or lower product sales revenue or cost of product sales when the physical sale or purchase of those products occurs. These contracts may be for the purchase or sale of products in markets different from those in which we are attempting to hedge our exposure, and the resulting hedges may not eliminate all price risks.

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk.

We entered into $100.0 million of forward-starting interest rate swap agreements during 2016 to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2018. The fair value of these contracts at June 30, 2017 was a net asset of $12.6 million. We account for these agreements as cash flow hedges. A 0.125% decrease in interest rates would result in a decrease in the fair value of this asset of approximately $2.6 million. A 0.125% increase in interest rates would result in an increase in the fair value of approximately $2.5 million.

ITEM 4. CONTROLS AND PROCEDURES

We performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner’s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner’s Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. Additionally, these disclosure controls and practices are effective in ensuring that information required to be disclosed is accumulated and communicated to our Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosures. There has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act) during the quarter ended June 30, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements within the meaning of the federal securities laws that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as “anticipates,” “believes,” “continue,” “could,” “estimates,” “expects,” “forecasts,” “goal,” “guidance,” “intends,” “may,” “might,” “plans,” “potential,” “projected,” “scheduled,” “should,” “will” and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

The following are among the important factors that could cause future results to differ materially from any projected, forecasted, estimated or budgeted amounts we have discussed in this report:

- overall demand for refined products, crude oil, liquefied petroleum gases and ammonia in the U.S.;
- price fluctuations for refined products, crude oil, liquefied petroleum gases and ammonia and expectations about future prices for these products;
- changes in the production of crude oil in the basins served by our pipelines;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties, lenders or joint venture co-owners;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy, refinance our existing obligations when due and maintain adequate liquidity;
- development of alternative energy sources, including but not limited to natural gas, solar power, wind power, electric and battery-powered engines and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, increased use of electric vehicles, as well as regulatory developments or other trends that could affect demand for our services;
- changes in the throughput or interruption in service of refined products or crude oil pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our refined products, crude oil or marine terminals;
- changes in supply and demand patterns for our facilities due to geopolitical events, the activities of the Organization of the Petroleum Exporting Countries, changes in U.S. trade policies or in laws governing the importing and exporting of petroleum products, technological developments or other factors;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates or other terms of service implemented by the Federal Energy Regulatory Commission, the U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants, ammonia production facilities or other customers or businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, protests or political activism, operational hazards, equipment failures, system failures or unforeseen interruptions;
- our ability to obtain adequate levels of insurance at a reasonable cost, and the potential for losses to exceed the insurance coverage we do obtain;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify expansion projects or to complete identified expansion projects on time and at projected costs;

- our ability to make and integrate accretive acquisitions and joint ventures and successfully execute our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- our ability to cooperate with and rely on our joint venture co-owners;
- actions by rating agencies concerning our credit ratings;
- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and to construct, acquire and operate any new or modified assets;
- our ability to promptly obtain all necessary services, materials, labor, supplies and rights-of-way required for construction of our growth projects, and to complete construction without significant delays, disputes or cost overruns;
- risks inherent in the use and security of information systems in our business and implementation of new software and hardware;
- changes in laws and regulations that govern product quality specifications or renewable fuel obligations that could impact our ability to produce gasoline volumes through our butane blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we or our customers are or could become subject, including tax withholding requirements, safety, security, employment, hydraulic fracturing, derivatives transactions, trade and environmental laws and regulations, including laws and regulations designed to address climate change;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability and intent of our customers, vendors, lenders, joint venture co-owners or other third parties to perform on their contractual obligations to us;
- petroleum product supply disruptions;
- global and domestic repercussions from terrorist activities, including cyber attacks, and the government’s response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of petroleum products and ammonia, and the operation, acquisition and construction of assets related to such activities.

This list of important factors is not exclusive. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changes in assumptions or otherwise.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Anhydrous Ammonia Event. On October 17, 2016, we experienced a release of anhydrous ammonia on our ammonia pipeline system near Tekamah, Nebraska. The release resulted in a fatality and other possible injuries. The National Transportation Safety Board is investigating the event. We are currently unable to estimate the full impact of this event. However, we believe the impact on our financial position and results of operations is not likely to be material as defined by the SEC.

Settlement of Clean Water Act Claims. In July 2011, we received an information request from the Environmental Protection Agency ("EPA") pursuant to Section 308 of the Clean Water Act regarding a pipeline release near Texas City, Texas in February 2011 (the "Texas Release"). In April 2012, we received a similar information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release near Nemaha, Nebraska in December 2011 (the "Nebraska Release"). In October 2015, we received a letter from the U.S. Department of Justice ("DOJ Letter") stating that the Clean Water Act claims arising out of the Texas Release, the Nebraska Release and a pipeline release near El Dorado, Kansas in May 2015 had all been referred to the DOJ for enforcement. In January 2017, we agreed to settle these enforcement claims for payment of $2 million and certain related injunctive relief regarding ongoing remediation efforts and future training and safety matters. The settlement was finalized and the settlement amount was paid in May 2017.

U.S. Oil Recovery, EPA ID No.: TXN000607093 Superfund Site. We have liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party ("PRP") under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended ("CERCLA"). As a result of the EPA's Administrative Settlement Agreement and Order on Consent for Removal Action, filed August 25, 2011, EPA Region 6, CERCLA Docket No. 06-10-11, we voluntarily entered into the PRP group responsible for the site investigation, stabilization and subsequent site cleanup. We have paid $15,000 associated with the assessment phase. Until this assessment phase has been completed, we cannot reasonably estimate our proportionate share of the remediation costs associated with this site. While the results cannot be reasonably estimated, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

Lake Calumet Cluster Site, EPA ID No.: ILD000716852 Superfund Site. We have liability at the Lake Calumet Cluster Superfund Site in Chicago, Illinois as a PRP under Sections 107(a) and 113(f)(1) of CERCLA. As a result of the EPA's Administrative Settlement Agreement and Order for Remedial Investigation/Feasibility Study of June 2013, we voluntarily entered into the PRP group responsible for the investigation, cleanup and installation of an appropriate clay cap over the site. We have paid $8,000 associated with the Remedial Investigation/Feasibility Study and cleanup costs to date. Our projected portion of the estimated cap installation is $55,000. While the results cannot be predicted with certainty, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our future results of operations, financial position or cash flows.

ITEM 1A. RISK FACTORS

In addition to the information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2016, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also could materially adversely affect our business, financial condition or operating results.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

The exhibits listed on the accompanying Index to Exhibits are filed or incorporated by reference as part of this report, and such Index to Exhibits is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized in Tulsa, Oklahoma on August 2, 2017.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: Magellan GP, LLC,
its general partner

/s/ Aaron L. Milford

Aaron L. Milford
Chief Financial Officer
(Principal Accounting and Financial Officer)

INDEX TO EXHIBITS

Exhibit Number		**Description**
Exhibit 12	—	Ratio of earnings to fixed charges.
Exhibit 31.1	—	Certification of Michael N. Mears, principal executive officer.
Exhibit 31.2	—	Certification of Aaron L. Milford, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of Aaron L. Milford, Chief Financial Officer.
Exhibit 101.INS	—	XBRL Instance Document.
Exhibit 101.SCH	—	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	—	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	—	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase.