Duff & Phelps Global Utility Income Fund Inc.
Form N-Q
March 17, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM N-Q

QUARTERLY SCHEDULE OF PORTFOLIO HOLDINGS OF REGISTERED

MANAGEMENT INVESTMENT COMPANY

Investment Company Act file number 811-22533

Duff & Phelps Global Utility Income Fund Inc.

(Exact name of registrant as specified in charter)

200 South Wacker Drive, Suite 500

Chicago, Illinois 60606

(Address of principal executive offices) (Zip code)

Alan M. Meder	Lawrence R. Hamilton, Esq.
Duff & Phelps Global Utility Income Fund Inc.	Mayer Brown LLP
200 South Wacker Drive, Suite 500	71 South Wacker Drive
Chicago, Illinois 60606	Chicago, Illinois 60606

(Name and address of agent for service)

Registrant s telephone number, including area code: 312-368-5510

Date of fiscal year end: October 31

Date of reporting period: January 31, 2017

Item 1. Schedule of Investments.

See the Statement of Net Assets below.

DUFF & PHELPS GLOBAL UTILITY INCOME FUND INC.

STATEMENT OF NET ASSETS

JANUARY 31, 2017

(Unaudited)

Shares	Description	Value
COMMON STOCKS & MLP INTERESTS 132.3%		
	ELECTRIC, GAS AND WATER 41.9%	
1,670,000	CenterPoint Energy, Inc.	$43,770,700
860,000	Emera, Inc. (Canada)	30,031,431
866,000	innogy SE (Germany)(2)	29,620,781
2,871,000	National Grid plc (United Kingdom)	33,506,016
218,000	NextEra Energy, Inc.	26,970,960
731,700	Southern Co.	36,167,931
2,900,381	United Utilities Group plc (United Kingdom)	33,458,497
564,000	WEC Energy Group, Inc.	33,304,200
656,293	Westar Energy, Inc.	35,892,664
		302,723,180
	OIL & GAS STORAGE, TRANSPORTATION AND PRODUCTION 59.1%	
4,287,455	APA Group (Australia)	27,378,426
480,184	DCP Midstream LP	18,664,752
688,861	Enbridge Energy Partners LP	13,343,238
536,346	Energy Transfer Partners LP	20,461,600
802,800	Enterprise Products Partners LP	22,743,324
500,000	GasLog Partners LP (Marshall Islands)	11,450,000
355,500	Genesis Energy LP	12,893,985
1,431,854	Kinder Morgan, Inc.	31,987,618
484,223	KNOT Offshore Partners LP (Marshall Islands)	10,556,061
400,575	MPLX LP	15,161,764
285,716	NuStar Energy LP	15,802,952
856,000	Pembina Pipeline Corp. (Canada)	26,556,557
756,000	Plains All American Pipeline LP	23,730,840
710,000	Sunoco Logistics Partners LP	18,119,200
500,000	Sunoco LP	14,150,000
343,298	Tallgrass Energy Partners LP	16,986,385
446,528	Targa Resources Corp.	25,728,943
278,834	TC Pipelines LP	16,752,347
1,080,000	TransCanada Corp. (Canada)	50,951,931
814,270	Williams Partners LP	33,417,641
		426,837,564
	TELECOMMUNICATIONS 31.3%	
810,000	BCE, Inc. (Canada)	36,547,200
1,119,440	Communications Sales & Leasing, Inc.	29,418,883
225,000	Crown Castle International Corp.	19,761,750
2,974,000	Frontier Communications Corp.	10,379,260
1,468,000	Orange SA (France)	22,701,031
15,565,000	Spark New Zealand Ltd. (New Zealand)	40,084,486
6,211,000	Telia Company AB (Sweden)	25,185,967
6,860,000	Telstra Corp., Ltd. (Australia)	26,013,029

1,978,200	Windstream Holdings, Inc.	15,983,856
		226,075,462
	Total Common Stocks & MLP Interests (Cost $873,432,863)	955,636,206

The accompanying notes are an integral part of this financial statement.

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DUFF & PHELPS GLOBAL UTILITY INCOME FUND INC.

STATEMENT OF NET ASSETS (Continued)

JANUARY 31, 2017

(Unaudited)

Shares	Description	Value
SHORT-TERM INVESTMENT 2.9%		
	MONEY MARKET MUTUAL FUND 2.9%	
21,240,386	BlackRock Liquidity Funds FedFund Portfolio Institutional Shares (seven-day effective yield 0.470%)[3]	$21,240,386
	Total Short-term Investment (Cost $21,240,386)	21,240,386
TOTAL INVESTMENTS 135.2% (Cost $894,673,249)		976,876,592[1]
Secured borrowings (22.1)%		(160,000,000)
Mandatory Redeemable Preferred Shares at liquidation value (13.8)%		(100,000,000)
Other assets less other liabilities 0.7%		5,839,766
NET ASSETS APPLICABLE TO COMMON STOCK 100.0%		$722,716,358

(1) All or a portion of the total investments have been pledged as collateral for borrowings.
(2) Non-income producing.
(3) Shares of this fund are publicly offered and its prospectus and annual report are publicly available.

The percentage shown for each investment category is the total value of that category as a percentage of the net assets applicable to common stock of the Fund.

The accompanying notes are an integral part of this financial statement.

DUFF & PHELPS GLOBAL UTILITY INCOME FUND INC.

STATEMENT OF NET ASSETS (Continued)

JANUARY 31, 2017

(Unaudited)

SECTOR ALLOCATIONS *

Oil & Gas Storage, Transportation and Production	44%
Electric, Gas and Water	31
Telecommunications	23
Money Market Mutual Fund	2
Total	100%

COUNTRY WEIGHTINGS *

United States	59%
Canada	15
United Kingdom	7
Australia	5
New Zealand	4
Germany	3
Sweden	3
France	2
Marshall Islands	2
Total	100%

CURRENCY EXPOSURE *

United States Dollar	65%
Canadian Dollar	11
British Pound	7
Australian Dollar	5
Euro	5
New Zealand Dollar	4
Swedish Krona	3
Total	100%

* Percentages are based on total investments rather than net assets applicable to common stock.

The accompanying notes are an integral part of this financial statement.

DUFF & PHELPS GLOBAL UTILITY INCOME FUND INC.

STATEMENT OF NET ASSETS (Continued)

JANUARY 31, 2017

(Unaudited)

Note 1. Investment Valuation

The Fund s investments are carried at fair value which is defined as the price that the Fund would receive upon selling an investment in a timely transaction to an independent buyer in the principal or most advantageous market of the investment. The three-tier hierarchy of inputs established to classify fair value measurements for disclosure purposes is summarized in the three broad levels listed below:

Level 1 quoted prices in active markets for identical securities

Level 2 other significant observable inputs (including quoted prices for similar securities, interest rates, prepayment spreads, credit risks, etc.)

Level 3 significant unobservable inputs (including the Fund s own assumptions in determining fair value of investments)

The inputs or methodology used for valuing securities are not necessarily an indication of the risk associated with investing in these securities. For more information about the Fund s policy regarding valuation of investments and other significant accounting policies, please refer to the Fund s most recent financial statements contained in its annual report. The following is a summary of the inputs used to value each of the Fund s investments at January 31, 2017:

	Level 1
Common stocks & MLP interests	$955,636,206
Money market mutual fund	21,240,386
Total	$976,876,592

There were no Level 2 or Level 3 priced securities held and there were no transfers between Level 1 and Level 2 related to securities held at January 31, 2017.

Note 2. Federal Income Tax Information

At October 31, 2016, the Fund s most recent fiscal tax year-end, the federal tax cost and aggregate gross unrealized appreciation (depreciation) were as follows:

	Federal Tax Cost	**Unrealized Appreciation**	**Unrealized Depreciation**	**Net Unrealized Appreciation**
Investments	$862,532,332	$159,321,971	$(66,181,114)	$93,140,857

The difference between the book basis and tax basis of unrealized appreciation (depreciation) and cost of investments is primarily attributable to investments in MLPs.

Other information regarding the Fund is available on the Fund s website at www.dpgfund.com or the Securities and Exchange Commission s website at www.sec.gov.

Item 2. Controls and Procedures.

(a) The registrant s principal executive officer and principal financial officer have concluded that the registrant s disclosure controls and procedures (as defined in Rule 30a-3(c) under the Investment Company Act of 1940 (the 1940 Act)) are effective, based on an evaluation of those controls and procedures made as of a date within 90 days of the filing date of this report as required by Rule 30a-3(b) under the 1940 Act and Rule 13a-15(b) under the Securities Exchange Act of 1934.

(b) There has been no change in the registrant s internal control over financial reporting (as defined in Rule 30a-3(d) under the 1940 Act) that occurred during the registrant s last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant s internal control over financial reporting.

Item 3. Exhibits.

Exhibit 99.CERT	Certifications pursuant to Rule 30a-2(a) under the 1940 Act and Section 302 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934 and the Investment Company Act of 1940, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

(Registrant) Duff & Phelps Global Utility Income Fund Inc.

By (Signature and Title)* /s/ Nathan I. Partain
Nathan I. Partain

President and Chief Executive Officer
(Principal Executive Officer)

Date March 17, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934 and the Investment Company Act of 1940, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By (Signature and Title)* /s/ Nathan I. Partain
Nathan I. Partain

President and Chief Executive Officer
(Principal Executive Officer)

Date March 17, 2017

By (Signature and Title)* /s/ Alan M. Meder
Alan M. Meder

Treasurer and Assistant Secretary
(Principal Financial Officer)

Date March 17, 2017

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Three Months Ended
June 30,

Six Months Ended
June 30,

2015

2014

2015

2014
REVENUES:

Pipeline transportation services
20,191

23,192

40,049

44,112

Refinery services
46,324

52,801

92,448

106,994

Marine transportation
62,594

55,948

119,965

112,241

Supply and logistics
527,218

883,108

930,722

1,771,421

Total revenues
656,327

1,015,049

1,183,184

2,034,768

COSTS AND EXPENSES:

Supply and logistics product costs
492,125

844,395

863,043

1,693,657

Supply and logistics operating costs
23,782

27,774

49,021

55,092

Marine transportation operating costs
35,286

36,905

66,880

72,679

Refinery services operating costs
25,835

31,148

52,862

64,343

Pipeline transportation operating costs
6,882

8,383

13,796

15,861

General and administrative
14,832

14,696

28,053

26,706

Depreciation and amortization
28,205

20,491

55,330

39,771

Total costs and expenses
626,947

983,792

1,128,985

1,968,109

OPERATING INCOME
29,380

31,257

54,199

66,659

Equity in earnings of equity investees
18,661

4,922

34,180

12,740

Interest expense
(17,905
)

(14,069

)

(37,120
)

(26,873
)
Other income/(expense), net
(17,529
)

—

(17,529
)

—

Income before income taxes
12,607

22,110

33,730

52,526

Income tax expense
(942
)

(962
)

(1,850
)

(1,603
)
NET INCOME
$
11,665

$
21,148

$
31,880

$
50,923

NET INCOME PER COMMON UNIT:

Basic and Diluted
$
0.12

$
0.24

$
0.33

$
0.57

WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:

Basic and Diluted
99,174

88,691

97,113

88,691

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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GENESIS ENERGY, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Number of Common Units		Partners' Capital	
	2015	2014	2015	2014
Partners' capital, January 1	95,029	88,691	$1,229,203	$1,097,737
Net income	—	—	31,880	50,923
Cash distributions	—	—	(117,316)	(96,236)
Issuance of common units for cash, net	4,600	—	197,722	—
Partners' capital, June 30	99,629	88,691	$1,341,489	$1,052,424

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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GENESIS ENERGY, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Six Months Ended June 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$31,880	$50,923
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation and amortization	55,330	39,771
Amortization of debt issuance costs and premium	6,526	2,320
Amortization of unearned income and initial direct costs on direct financing leases	(7,566)	(7,922)
Payments received under direct financing leases	10,333	10,631
Equity in earnings of investments in equity investees	(34,180)	(12,740)
Cash distributions of earnings of equity investees	38,811	21,452
Non-cash effect of equity-based compensation plans	4,744	6,267
Deferred and other tax liabilities	1,250	853
Unrealized loss (gain) on derivative transactions	1,309	(1,187)
Other, net	(2,296)	1,518
Net changes in components of operating assets and liabilities (Note 13)	(35,039)	(6,689)
Net cash provided by operating activities	71,102	105,197
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(240,646)	(240,994)
Cash distributions received from equity investees - return of investment	11,490	6,173
Investments in equity investees	(1,750)	(14,826)
Proceeds from asset sales	2,228	133
Other, net	(729)	(2,635)
Net cash used in investing activities	(229,407)	(252,149)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on senior secured credit facility	550,500	1,181,200
Repayments on senior secured credit facility	(515,700)	(1,271,800)
Proceeds from issuance of senior unsecured notes	400,000	350,000
Repayment of senior unsecured notes	(350,000)	—
Debt issuance costs	(8,418)	(10,752)
Issuance of common units for cash, net	197,722	—
Distributions to common unitholders	(117,316)	(96,236)
Other, net	774	—
Net cash provided by financing activities	157,562	152,412
Net increase in cash and cash equivalents	(743)	5,460
Cash and cash equivalents at beginning of period	9,462	8,866
Cash and cash equivalents at end of period	$8,719	$14,326

The accompanying notes are an integral part of these Unaudited Condensed Consolidated Financial Statements.

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Basis of Presentation and Consolidation

Organization

We are a growth-oriented master limited partnership formed in Delaware in 1996 and focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida, Wyoming and in the Gulf of Mexico. We have a diverse portfolio of assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and trucks. We were formed in 1996 and are owned 100% by our limited partners. Genesis Energy, LLC, our general partner, is a wholly-owned subsidiary. Our general partner has sole responsibility for conducting our business and managing our operations. We conduct our operations and own our operating assets through our subsidiaries and joint ventures. We manage our businesses through the following five divisions that constitute our reportable segments:

- Onshore pipeline transportation of crude oil and, to a lesser extent, carbon dioxide (or "CO_2");
- Offshore pipeline transportation of crude oil in the Gulf of Mexico;
- Refinery services involving processing of high sulfur (or “sour”) gas streams for refineries to remove the sulfur, and selling the related by-product, sodium hydrosulfide (or “NaHS”, commonly pronounced "nash");
- Marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America; and
- Supply and logistics services, which include terminaling, blending, storing, marketing and transporting crude oil and petroleum products and, on a smaller scale, CO_2.

Basis of Presentation and Consolidation

The accompanying Unaudited Condensed Consolidated Financial Statements include Genesis Energy, L.P. and its subsidiaries, including Genesis Energy, LLC, our general partner.

Our results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. The Condensed Consolidated Financial Statements included herein have been prepared by us without audit pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, they reflect all adjustments (which consist solely of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of the financial results for interim periods. Certain information and notes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) have been condensed or omitted pursuant to such rules and regulations. However, we believe that the disclosures are adequate to make the information presented not misleading when read in conjunction with the information contained in the periodic reports we file with the SEC pursuant to the Securities Exchange Act of 1934, including the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

2. Subsequent Events

In July 2015, we acquired the offshore pipeline and services business of Enterprise Products Operating, LLC and its affiliates for approximately $1.5 billion. That business includes assets of approximately 2,350 miles of offshore crude oil and natural gas pipelines and six offshore hub platforms that serve some of the most active drilling and development regions in the United States, including deepwater production fields in the Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. At the closing of that transaction, we entered into transition service agreements to facilitate a smooth transition of operations and uninterrupted services for both employees and customers. That acquisition complements and substantially expands our existing offshore pipelines segment.

To finance that transaction, in July, we sold 10,350,000 common units in a public offering that generated proceeds of $437.2 million net of underwriter discounts and $750 million aggregate principal amount of 6.75% senior unsecured notes due 2022 that generated proceeds of $728.6 million net of issuance discount and underwriting fees. The financial statements and footnotes filed herewith do not include the effects of this transaction.

Due to the timing of the acquisition, our initial purchase accounting was incomplete at the time these financial statements were issued. As such, we cannot disclose the allocation of the acquisition price to acquired assets and liabilities and the related required disclosures at this time.

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3. Recent Accounting Developments
Recently Issued
In April 2015, the Financial Accounting Standards Board ("FASB") issued guidance that will require the presentation of debt issuance costs in financial statements as a direct reduction of related debt liabilities with amortization of debt issuance costs reported as interest expense. Under current U.S. GAAP standards, debt issuance costs are reported as deferred charges (i.e., as an asset). This guidance is effective for annual periods, and interim periods within those fiscal years, beginning after December 15, 2015 and is to be applied retrospectively upon adoption. Early adoption is permitted, including adoption in an interim period for financial statements that have not been previously issued. We are currently evaluating this guidance.
In May 2014, the FASB issued revised guidance on revenue from contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard provides a five-step analysis for transactions to determine when and how revenue is recognized. The guidance permits the use of either a full retrospective or a modified retrospective approach.
In July 2015, the FASB approved a one year deferral of the effective date of this standard to December 15, 2017 for annual reporting periods beginning after that date. The FASB also approved early adoption of the standard, but not before the original effective date of December 15, 2016. We are evaluating the transition methods and the impact of the amended guidance on our financial position, results of operations and related disclosures.
4. Acquisition and Divestiture
Acquisition
M/T American Phoenix
On November 13, 2014, we acquired the M/T American Phoenix from Mid Ocean Tanker Company for $157 million. The M/T American Phoenix is a modern double-hulled, Jones Act qualified tanker with 330,000 barrels of cargo capacity that was placed into service during 2012.
The purchase price of $157 million was paid to Mid Ocean Tanker Company in cash, as funded with proceeds from available and committed liquidity under our $1 billion revolving credit facility. We have reflected the financial results of the acquired business in our marine transportation segment from the date of acquisition. We have recorded the assets acquired in the Consolidated Financial Statements at their fair values. Those fair values were developed by management.
The allocation of the purchase price, as presented on our Consolidated Balance Sheet, is summarized as follows:

Property and equipment	$125,000
Intangible assets	32,000
Total purchase price	$157,000

Our Consolidated Financial Statements include the results of our acquired offshore marine transportation business since November 13, 2014, the effective closing date of the acquisition. The following table presents selected financial information included in our Consolidated Financial Statements for the periods presented:

	Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
Revenues	$5,642	$11,222
Net income	$1,274	$2,671

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The table below presents selected unaudited pro forma financial information incorporating the historical results of our M/T American Phoenix. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2014 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. Depreciation expense for the fixed assets acquired is calculated on a straight-line basis over an estimated useful life of approximately 30 years.

	Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
Pro forma consolidated financial operating results:		
Revenues	$1,019,900	$2,044,470
Net Income	$22,478	$53,551

5. Inventories

The major components of inventories were as follows:

	June 30, 2015	December 31, 2014
Petroleum products	$28,043	$30,108
Crude oil	20,636	7,266
Caustic soda	2,320	2,850
NaHS	3,567	6,603
Other	—	2
Total	$54,566	$46,829

Inventories are valued at the lower of cost or market. At June 30, 2015, market values of our inventories exceeded recorded costs. At December 31, 2014 , market value of inventories was below recorded costs by approximately $6.6 million, so we reduced the value of inventory as of that date in our Condensed Consolidated Financial Statements for this difference.

6. Fixed Assets

Fixed Assets

Fixed assets consisted of the following:

	June 30, 2015	December 31, 2014
Pipelines and related assets	$477,815	$466,613
Machinery and equipment	393,913	376,672
Transportation equipment	17,216	18,479
Marine vessels	750,444	731,016
Land, buildings and improvements	39,772	38,037
Office equipment, furniture and fixtures	7,126	6,696
Construction in progress	387,903	222,233
Other	46,457	39,312
Fixed assets, at cost	2,120,646	1,899,058
Less: Accumulated depreciation	(304,876)	(268,057)
Net fixed assets	$1,815,770	$1,631,001

Our depreciation expense for the periods presented was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Depreciation expense	$22,512	$16,409	$44,549	$31,686

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

7. Equity Investees
We account for our ownership in our joint ventures under the equity method of accounting. The price we pay to acquire an ownership interest in a company may exceed the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our equity investees. At June 30, 2015 and December 31, 2014, the unamortized excess cost amounts totaled $210.2 million and $215.4 million, respectively. We amortize the excess cost as a reduction in equity earnings in a manner similar to depreciation.
The following table presents information included in our Unaudited Condensed Consolidated Financial Statements related to our equity investees.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Genesis' share of operating earnings	$21,403	$7,505	$39,663	$17,906
Amortization of excess purchase price	(2,742)	(2,583)	(5,483)	(5,166)
Net equity in earnings	$18,661	$4,922	$34,180	$12,740
Distributions received	$24,399	$15,045	$50,301	$27,625

The following tables present the combined unaudited balance sheet and income statement information (on a 100% basis) of our equity investees:

	June 30, 2015	December 31, 2014
BALANCE SHEET DATA:		
Assets		
Current assets	$50,963	$42,135
Fixed assets, net	989,168	1,015,305
Other assets	1,938	4,369
Total assets	$1,042,069	$1,061,809
Liabilities and equity		
Current liabilities	$26,521	$25,369
Other liabilities	202,633	202,613
Equity	812,915	833,827
Total liabilities and equity	$1,042,069	$1,061,809

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
INCOME STATEMENT DATA:				
Revenues	$82,553	$46,440	$154,643	$96,264
Operating income	$56,408	$22,628	$104,521	$53,103
Net income	$55,230	$21,815	$102,147	$51,521

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

8. Intangible Assets
The following table summarizes the components of our intangible assets at the dates indicated:

	June 30, 2015			December 31, 2014		
	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Refinery Services:						
Customer relationships	$94,654	$ 84,083	$10,571	$94,654	$ 81,880	$12,774
Licensing agreements	38,678	30,339	8,339	38,678	28,983	9,695
Segment total	133,332	114,422	18,910	133,332	110,863	22,469
Supply & Logistics:						
Customer relationships	35,430	31,082	4,348	35,430	30,228	5,202
Intangibles associated with lease	13,260	3,749	9,511	13,260	3,512	9,748
Segment total	48,690	34,831	13,859	48,690	33,740	14,950
Marine contract intangibles	32,000	3,333	28,667	32,000	833	31,167
Other	21,533	7,055	14,478	22,797	8,452	14,345
Total	$235,555	$ 159,641	$75,914	$236,819	$ 153,888	$82,931

Our amortization of intangible assets for the periods presented was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Amortization of intangible assets	$4,154	$3,147	$8,191	$6,292

We estimate that our amortization expense for the next five years will be as follows:

Remainder of 2015	$9,761
2016	$15,628
2017	$14,465
2018	$12,349
2019	$8,036

9. Debt
Our obligations under debt arrangements consisted of the following:

	June 30, 2015	December 31, 2014
Senior secured credit facility	$585,200	$550,400
7.875% senior unsecured notes (including unamortized premium of $639 in 2014)	—	350,639
6.000% senior unsecured notes	400,000	—
5.750% senior unsecured notes	350,000	350,000
5.625% senior unsecured notes	350,000	350,000
Total long-term debt	$1,685,200	$1,601,039

As of June 30, 2015, we were in compliance with the financial covenants contained in our credit agreement and senior unsecured notes indentures.

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Senior Secured Credit Facility

The key terms for rates under our $1 billion senior secured credit facility, which are dependent on our leverage ratio (as defined in the credit agreement), are as follows:

- The applicable margin varies from 1.50% to 2.50% on Eurodollar borrowings and from 0.50% to 1.50% on alternate base rate borrowings.
- Letter of credit fees range from 1.50% to 2.50%
- The commitment fee on the unused committed amount will range from 0.250% to 0.375%.
- The accordion feature was increased from $300 million to $500 million, giving us the ability to expand the size of the facility up to $1.5 billion for acquisitions or growth projects, subject to lender consent.

At June 30, 2015, we had $585.2 million borrowed under our $1 billion credit facility, with $43.4 million of the borrowed amount designated as a loan under the inventory sublimit. The credit agreement allows up to $100 million of the capacity to be used for letters of credit, of which $30.6 million was outstanding at June 30, 2015. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date. The total amount available for borrowings under our credit facility at June 30, 2015 was $384.2 million.

Senior Unsecured Note Issuance and Repayment

On May 21, 2015, we issued $400 million in aggregate principal amount of 6.0% senior unsecured notes at face value. Interest payments are due on May 15 and November 15 of each year with the initial interest payment due November 15, 2015. Those notes mature on May 15, 2023. We used a portion of the proceeds from those notes to redeem all of our outstanding $350 million, 7.875% senior unsecured notes due 2018. The aggregate principal amount of the 7.875% notes totaling $300.1 million were tendered and the remaining $49.9 million were redeemed in full. A total loss of approximately $19.2 million for the tender and redemption of notes is recorded to "Other income/(expense), net" in our Consolidated Statements of Operations.

10. Partners’ Capital and Distributions

At June 30, 2015, our outstanding common units consisted of 99,589,221 Class A units and 39,997 Class B units.

On April 10, 2015, we issued 4,600,000 Class A common units in a public offering at a price of $44.42 per unit, which included the exercise by the underwriters of an option to purchase up to 600,000 additional common units from us. We received proceeds, net of underwriting discounts and offering costs, of approximately $198 million from that offering. We intend to use the net proceeds for general partnership purposes, including funding acquisitions (including organic growth projects) or repaying a portion of the borrowings outstanding under our revolving credit facility.

Distributions

We paid or will pay the following distributions in 2014 and 2015:

Distribution For	Date Paid		Per Unit Amount	Total Amount
2014				
1st Quarter	May 15, 2014		$0.5500	$48,783
2nd Quarter	August 14, 2014		$0.5650	$50,114
3rd Quarter	November 14, 2014		$0.5800	$54,112
4th Quarter	February 13, 2015		$0.5950	$56,542
2015				
1st Quarter	May 15, 2015		$0.6100	$60,774
2nd Quarter	August 14, 2015	(1)	$0.6250	$68,737

(1) This distribution will be paid to unitholders of record as of July 31, 2015.

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11. Business Segment Information
In the fourth quarter of 2014, we reorganized our operating segments as a result of a change in the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and allocates resources. The results of our marine transportation activities, formerly reported in the Supply and Logistics Segment, are now reported in our Marine Transportation Segment. In addition, the results of our offshore and onshore pipeline transportation activities, formerly reported in the Pipeline Transportation Segment, are now reported separately in our Onshore Pipeline Transportation Segment and Offshore Pipeline Transportation Segment. Our disclosures related to prior periods have been recast to reflect our reorganized segments.
As a result of the above changes, we currently manage our businesses through five divisions that constitute our reportable segments:

- Onshore Pipeline Transportation – transportation of crude oil, and to a lesser extent, CO_2;
- Offshore Pipeline Transportation – offshore transportation of crude oil in the Gulf of Mexico;
- Refinery Services – processing high sulfur (or “sour”) gas streams as part of refining operations to remove the sulfur and selling the related by-product, NaHS;
- Marine Transportation – marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America; and
- Supply and Logistics – terminaling, blending, storing, marketing and transporting crude oil and petroleum products (primarily fuel oil, asphalt, and other heavy refined products) and, on a smaller scale, CO_2.

Substantially all of our revenues are derived from, and substantially all of our assets are located in, the United States.
We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our legacy stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases.
Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes, where relevant, and capital investment.

Segment information for the periods presented below was as follows:

	Onshore Pipeline Transportation	Offshore Pipeline Transportation	Refinery Services	Marine Transportation	Supply & Logistics	Total
Three Months Ended June 30, 2015						
Segment margin (a)	$14,363	$25,100	$20,221	$27,225	$11,658	$98,567
Capital expenditures (b)	$40,893	$86	$238	$11,086	$55,850	$108,153
Revenues:						
External customers	$15,856	$1,258	$48,786	$60,603	$529,824	$656,327
Intersegment (c)	3,077	—	(2,462)	1,991	(2,606)	—
Total revenues of reportable segments	$18,933	$1,258	$46,324	$62,594	$527,218	$656,327
Three Months Ended June 30, 2014						
Segment margin (a)	$16,531	$11,435	$21,627	$18,978	$14,110	$82,681
Capital expenditures (b)	$3,845	$3,192	$597	$37,077	$95,413	$140,124
Revenues:						
External customers	$19,236	$522	$55,552	$51,892	$887,847	$1,015,049
Intersegment (c)	3,434	—	(2,751)	4,056	(4,739)	—
Total revenues of reportable segments	$22,670	$522	$52,801	$55,948	$883,108	$1,015,049
Six Months Ended June 30, 2015						
Segment Margin (a)	$28,686	$50,298	$39,381	$52,918	$21,405	$192,688
Capital expenditures (b)	$109,484	$2,139	$1,450	$27,662	$92,626	$233,361
Revenues:						
External customers	$31,687	$2,048	$97,221	$115,243	$936,985	$1,183,184
Intersegment (c)	6,314	—	(4,773)	4,722	(6,263)	—
Total revenues of reportable segments	$38,001	$2,048	$92,448	$119,965	$930,722	$1,183,184
Six Months Ended June 30, 2014						
Segment Margin (a)	$31,220	$24,838	$42,499	$39,435	$22,040	$160,032
Capital expenditures (b)	$27,741	$13,576	$899	$48,036	$152,650	$242,902
Revenues:						
External customers	$34,739	$1,469	$112,659	$102,982	$1,782,919	$2,034,768
Intersegment (c)	7,904	—	(5,665)	9,259	(11,498)	—
Total revenues of reportable segments	$42,643	$1,469	$106,994	$112,241	$1,771,421	$2,034,768

Total assets by reportable segment were as follows:

	June 30, 2015	December 31, 2014
Onshore pipeline transportation	$516,365	$460,012
Offshore pipeline transportation	631,998	645,668
Refinery services	394,794	403,703

Marine transportation	754,515	745,128
Supply and logistics	1,042,620	907,189
Other assets	63,989	68,674
Total consolidated assets	3,404,281	3,230,374

(a) A reconciliation of Segment Margin to net income for the periods is presented below.

(b) Capital expenditures include maintenance and growth capital expenditures, such as fixed asset additions (including enhancements to existing facilities and construction of growth projects) as well as acquisitions of businesses and interests in equity investees. In addition to construction of growth projects, capital spending in our pipeline transportation segment included \$0.0 million and \$1.8 million during the three and six months ended June 30, 2015 and \$2.3 million and \$12.7

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million during the three and six months ended June 30, 2014 representing capital contributions to our SEKCO equity investee to fund our share of the construction costs for its pipeline.

(c) Intersegment sales were conducted under terms that we believe were no more or less favorable than then-existing market conditions.

Reconciliation of Segment Margin to net income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Segment Margin	$98,567	$82,681	$192,688	$160,032
Corporate general and administrative expenses	(13,953)	(13,789)	(26,252)	(24,850)
Depreciation and amortization	(28,205)	(20,491)	(55,330)	(39,771)
Interest expense	(17,905)	(14,069)	(37,120)	(26,873)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income (1)	(7,038)	(7,808)	(17,421)	(13,585)
Non-cash items not included in Segment Margin	1,771	(3,043)	(843)	282
Cash payments from direct financing leases in excess of earnings	(1,405)	(1,371)	(2,767)	(2,709)
Loss on extinguishment of debt	(19,225)	—	(19,225)	—
Income tax expense	(942)	(962)	(1,850)	(1,603)
Net income	$11,665	$21,148	31,880	50,923

(1) Includes distributions attributable to the quarter and received during or promptly following such quarter.

12. Transactions with Related Parties

Sales, purchases and other transactions with affiliated companies, in the opinion of management, are conducted under terms no more or less favorable than then-existing market conditions. The transactions with related parties were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues:				
Sales of CO_2 to Sandhill Group, LLC (1)	$806	$713	$1,505	$1,368
Costs and expenses:				
Amounts paid to our CEO in connection with the use of his aircraft	$165	$150	$360	$300

(1) We own a 50% interest in Sandhill Group, LLC.

Amount due from Related Party

At June 30, 2015 and December 31, 2014 Sandhill Group, LLC owed us $0.3 million, respectively, for purchases of CO_2.

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13. Supplemental Cash Flow Information
The following table provides information regarding the net changes in components of operating assets and liabilities.

	Six Months Ended June 30, 2015	2014
(Increase) decrease in:		
Accounts receivable	$202	$20,827
Inventories	(7,737)	(44,523)
Deferred charges	(7,725)	—
Other current assets	2,286	47,542
Increase (decrease) in:		
Accounts payable	(5,998)	13,436
Accrued liabilities	(16,067)	(43,971)
Net changes in components of operating assets and liabilities	(35,039)	(6,689)

Payments of interest and commitment fees, net of amounts capitalized, were $40.3 million and $33.4 million for the six months ended June 30, 2015 and June 30, 2014, respectively. We capitalized interest of $7.2 million and $10.0 million during the six months ended June 30, 2015 and June 30, 2014.
At June 30, 2015 and June 30, 2014, we had incurred liabilities for fixed and intangible asset additions totaling $52.9 million and $42.1 million, respectively, that had not been paid at the end of the second quarter, and, therefore, were not included in the caption “Payments to acquire fixed and intangible assets” under Cash Flows from Investing Activities in the Unaudited Condensed Consolidated Statements of Cash Flows.
At June 30, 2015 we had incurred liabilities for other asset additions totaling $12.7 million, that had not been paid at the end of the second quarter and, therefore, were not included in the caption "Other, net" under Cash Flows from Investing Activities in the Unaudited Condensed Consolidated Statements of Cash Flows.
14. Derivatives
Commodity Derivatives
We have exposure to commodity price changes related to our inventory and purchase commitments. We utilize derivative instruments (primarily futures and options contracts traded on the NYMEX) to hedge our exposure to commodity prices, primarily of crude oil, fuel oil and petroleum products. Our decision as to whether to designate derivative instruments as fair value hedges for accounting purposes relates to our expectations of the length of time we expect to have the commodity price exposure and our expectations as to whether the derivative contract will qualify as highly effective under accounting guidance in limiting our exposure to commodity price risk. Most of the petroleum products, including fuel oil that we supply, cannot be hedged with a high degree of effectiveness with derivative contracts available on the NYMEX; therefore, we do not designate derivative contracts utilized to limit our price risk related to these products as hedges for accounting purposes. Typically we utilize crude oil and other petroleum products futures and option contracts to limit our exposure to the effect of fluctuations in petroleum products prices on the future sale of our inventory or commitments to purchase petroleum products, and we recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales. The recognition of changes in fair value of the derivative contracts not designated as hedges for accounting purposes can occur in reporting periods that do not coincide with the recognition of gain or loss on the actual transaction being hedged. Therefore we will, on occasion, report gains or losses in one period that will be partially offset by gains or losses in a future period when the hedged transaction is completed.
We have designated certain crude oil futures contracts as hedges of crude oil inventory due to our expectation that these contracts will be highly effective in hedging our exposure to fluctuations in crude oil prices during the period that we expect to hold that inventory. We account for these derivative instruments as fair value hedges under the

accounting guidance. Changes in the fair value of these derivative instruments designated as fair value hedges are used to offset related changes in the fair value of the hedged crude oil inventory. Any hedge ineffectiveness in these fair value hedges and any amounts excluded from effectiveness testing are recorded as a gain or loss in the consolidates statements of operations.

In accordance with NYMEX requirements, we fund the margin associated with our loss positions on commodity derivative contracts traded on the NYMEX. The amount of the margin is adjusted daily based on the fair value of the commodity contracts. The margin requirements are intended to mitigate a party's exposure to market volatility and the

associated contracting party risk. We offset fair value amounts recorded for our NYMEX derivative contracts against margin funding as required by the NYMEX in Current Assets - Other in our Consolidated Balance Sheets.
At June 30, 2015, we had the following outstanding derivative commodity contracts that were entered into to economically hedge inventory or fixed price purchase commitments.

	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	188	—
Weighted average contract price per bbl	$57.50	$—
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	402	206
Weighted average contract price per bbl	$60.72	$62.87
Crude oil swaps:		
Contract volumes (1,000 bbls)	170	—
Weighted average contract price per bbl	$(2.11)	$—
Diesel futures:		
Contract volumes (1,000 bbls)	80	20
Weighted average contract price per gal	$1.89	$1.87
#6 Fuel oil futures:		
Contract volumes (1,000 bbls)	360	5
Weighted average contract price per bbl	$52.07	$53.35
Crude oil options:		
Contract volumes (1,000 bbls)	145	50
Weighted average premium received	$1.08	$0.27

Financial Statement Impacts
Unrealized gains are subtracted from net income and unrealized losses are added to net income in determining cash flows from operating activities. To the extent that we have fair value hedges outstanding, the offsetting change recorded in the fair value of inventory is also eliminated from net income in determining cash flows from operating activities. Changes in margin deposits necessary to fund unrealized losses also affect cash flows from operating activities.

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The following tables reflect the estimated fair value gain (loss) position of our derivatives at June 30, 2015 and December 31, 2014:
Fair Value of Derivative Assets and Liabilities

	Unaudited Condensed Consolidated Balance Sheets Location	Fair Value June 30, 2015	December 31, 2014
Asset Derivatives:			
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$363	$16,383
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(363)	(2,310)
Net amount of assets presented in the Unaudited Condensed Consolidated Balance Sheets		$—	$14,073
Commodity derivatives - futures and call options (designated hedges):			
Gross amount of recognized assets	Current Assets - Other	$8	$—
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(8)	—
Net amount of assets presented in the Unaudited Condensed Consolidated Balance Sheets		$—	$—
Liability Derivatives:			
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(1,366)	$(2,310)
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other (1)	1,366	2,310
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets		$—	$—
Commodity derivatives - futures and call options (designated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(480)	$—
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other (1)	480	—
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets		$—	$—

(1) These derivative liabilities have been funded with margin deposits recorded in our Unaudited Condensed Consolidated Balance Sheets under Current Assets - Other.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of June 30, 2015, we had a net broker receivable of approximately $2.6

million (consisting of initial margin of $3.5 million increased by $0.9 million of variation margin). As of December 31, 2014, we had a net broker receivable of approximately $2.8 million (consisting of initial margin of $2.4 million increased by $0.3 million of variation margin). At June 30, 2015 and December 31, 2014, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

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Effect on Operating Results

	Unaudited Condensed Consolidated Statements of Operations Location	Amount of Gain (Loss) Recognized in Income Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Commodity derivatives - futures and call options:					
Contracts designated as hedges under accounting guidance	Supply and logistics product costs	$(4,021)	$—	$(1,835)	$—
Contracts not considered hedges under accounting guidance	Supply and logistics product costs	(4,209)	727	(5,014)	3,496
Total commodity derivatives		$(8,230)	$727	$(6,849)	$3,496

15. Fair-Value Measurements

We classify financial assets and liabilities into the following three levels based on the inputs used to measure fair value:

(1) Level 1 fair values are based on observable inputs such as quoted prices in active markets for identical assets and liabilities;

(2) Level 2 fair values are based on pricing inputs other than quoted prices in active markets for identical assets and liabilities and are either directly or indirectly observable as of the measurement date; and

(3) Level 3 fair values are based on unobservable inputs in which little or no market data exists.

As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014.

Recurring Fair Value Measures	Fair Value at June 30, 2015 Level 1	Level 2	Level 3	Fair Value at December 31, 2014 Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$371	$—	$—	$16,383	$—	$—
Liabilities	$(1,846)	$—	$—	$(2,310)	$—	$—

Our commodity derivatives include exchange-traded futures and exchange-traded options contracts. The fair value of these exchange-traded derivative contracts is based on unadjusted quoted prices in active markets and is, therefore, included in Level 1 of the fair value hierarchy.

See Note 14 for additional information on our derivative instruments.

Other Fair Value Measurements

We believe the debt outstanding under our credit facility approximates fair value as the stated rate of interest approximates current market rates of interest for similar instruments with comparable maturities. At June 30, 2015 our senior unsecured notes had a carrying value of $1.1 billion and a fair value of $1.1 billion, compared to $1.1 billion and $1.0 billion, respectively, at December 31, 2014. The fair value of the senior unsecured notes is determined based on trade information in the financial markets of our public debt and is considered a Level 2 fair value measurement.

16. Contingencies

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities; however, no assurance can be made that such environmental releases may not substantially affect our business.

We are subject to lawsuits in the normal course of business and examination by tax and other regulatory authorities. We do not expect such matters presently pending to have a material effect on our financial position, results of operations, or cash flows.

17. Condensed Consolidating Financial Information

Our $1.1 billion aggregate principal amount of senior unsecured notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P.’s current and future 100% owned domestic subsidiaries, except Genesis Free State Pipeline, LLC, Genesis NEJD Pipeline, LLC and certain other minor subsidiaries. Genesis NEJD Pipeline, LLC is 100% owned by Genesis Energy, L.P., the parent company. The remaining non-guarantor subsidiaries are owned by Genesis Crude Oil, L.P., a guarantor subsidiary. Genesis Energy Finance Corporation has no independent assets or operations. See Note 9 for additional information regarding our consolidated debt obligations.

During the second quarter of 2015, the Company took action related to certain non-guarantor subsidiaries that resulted in these subsidiaries previously categorized as non-guarantor subsidiaries becoming wholly owned guarantor subsidiaries. The changes made to guarantor subsidiaries did not impact the Company's previously reported consolidated net operating results, financial position, or cash flows. The condensed consolidating balance sheet as of December 31, 2014 and the condensed consolidating statements of operations for the three and six months ended June 30, 2014 as well as the condensed consolidating statements of cash flows for the six months ended June 30, 2014 have been retrospectively adjusted to reflect these updates to our guarantor subsidiaries as though the subsidiaries had been guarantors in all periods presented.

The following is condensed consolidating financial information for Genesis Energy, L.P., the guarantor subsidiaries and the non-guarantor subsidiaries.

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Unaudited Condensed Consolidating Balance Sheet
June 30, 2015

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$6	$—	$8,006	$707	$—	$8,719
Other current assets	1,406,653	—	338,521	50,763	(1,444,886)	351,051
Total current assets	1,406,659	—	346,527	51,470	(1,444,886)	359,770
Fixed assets, at cost	—	—	2,045,180	75,466	—	2,120,646
Less: Accumulated depreciation	—	—	(286,734)	(18,142)	—	(304,876)
Net fixed assets	—	—	1,758,446	57,324	—	1,815,770
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	29,677	—	267,482	143,627	(151,500)	289,286
Equity investees	—	—	614,409	—	—	614,409
Investments in subsidiaries	1,602,824	—	100,279	—	(1,703,103)	—
Total assets	$3,039,160	$—	$3,412,189	$252,421	$(3,299,489)	$3,404,281
LIABILITIES AND PARTNERS’ CAPITAL						
Current liabilities	$12,471	$—	$1,772,548	$2,113	$(1,445,014)	$342,118
Senior secured credit facility	585,200	—	—	—	—	585,200
Senior unsecured notes	1,100,000	—	—	—	—	1,100,000
Deferred tax liabilities	—	—	20,005	—	—	20,005
Other liabilities	—	—	15,470	151,331	(151,332)	15,469
Total liabilities	1,697,671	—	1,808,023	153,444	(1,596,346)	2,062,792
Partners’ capital	1,341,489	—	1,604,166	98,977	(1,703,143)	1,341,489
Total liabilities and partners’ capital	$3,039,160	$—	$3,412,189	$252,421	$(3,299,489)	$3,404,281

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Unaudited Condensed Consolidating Balance Sheet
December 31, 2014

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$9	$—	$8,310	$1,143	$—	$9,462
Other current assets	1,378,573	—	333,385	46,215	(1,412,269)	345,904
Total current assets	1,378,582	—	341,695	47,358	(1,412,269)	355,366
Fixed assets, at cost	—	—	1,823,556	75,502	—	1,899,058
Less: Accumulated depreciation	—	—	(251,171)	(16,886)	—	(268,057)
Net fixed assets	—	—	1,572,385	58,616	—	1,631,001
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	28,421	—	269,252	146,700	(154,192)	290,181
Equity investees	—	—	628,780	—	—	628,780
Investments in subsidiaries	1,434,255	—	97,195	—	(1,531,450)	—
Total assets	$2,841,258	$—	$3,234,353	$252,674	$(3,097,911)	$3,230,374
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$11,016	$—	$1,761,856	$2,705	$(1,412,432)	$363,145
Senior secured credit facility	550,400	—	—	—	—	550,400
Senior unsecured notes	1,050,639	—	—	—	—	1,050,639
Deferred tax liabilities	—	—	18,754	—	—	18,754
Other liabilities	—	—	18,233	154,021	(154,021)	18,233
Total liabilities	1,612,055	—	1,798,843	156,726	(1,566,453)	2,001,171
Partners' capital	1,229,203	—	1,435,510	95,948	(1,531,458)	1,229,203
Total liabilities and partners' capital	$2,841,258	$—	$3,234,353	$252,674	$(3,097,911)	$3,230,374

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unaudited Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2015

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Pipeline transportation services	$—	$ —	$14,378	$ 5,813	$—	$20,191
Refinery services	—	—	45,272	5,859	(4,807)	46,324
Marine transportation	—	—	62,594	—	—	62,594
Supply and logistics	—	—	529,073	(3,966)	2,111	527,218
Total revenues	—	—	651,317	7,706	(2,696)	656,327
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	517,230	(3,433)	2,110	515,907
Marine transportation costs	—	—	35,286	—	—	35,286
Refinery services operating costs	—	—	25,081	5,526	(4,772)	25,835
Pipeline transportation operating costs	—	—	6,974	(92)	—	6,882
General and administrative	—	—	14,861	(29)	—	14,832
Depreciation and amortization	—	—	28,249	(44)	—	28,205
Total costs and expenses	—	—	627,681	1,928	(2,662)	626,947
OPERATING INCOME	—	—	23,636	5,778	(34)	29,380
Equity in earnings of subsidiaries	48,777	—	2,099	—	(50,876)	—
Equity in earnings of equity investees	—	—	18,661	—	—	18,661
Interest (expense) income, net	(17,887)	—	3,787	(3,805)	—	(17,905)
Other income/(expense), net	(19,225)	—	1,696	—	—	(17,529)
Income before income taxes	11,665	—	49,879	1,973	(50,910)	12,607
Income tax benefit (expense)	—	—	(1,023)	81	—	(942)
NET INCOME	$11,665	$ —	$48,856	$ 2,054	$(50,910)	$11,665

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unaudited Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2014

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Pipeline transportation services	$—	$ —	$16,942	$ 6,250	$—	$23,192
Refinery services	—	—	51,694	4,571	(3,464)	52,801
Marine transportation	—	—	55,948	—	—	55,948
Supply and logistics	—	—	883,108	—	—	883,108
Total revenues	—	—	1,007,692	10,821	(3,464)	1,015,049
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	872,169	—	—	872,169
Marine transportation costs	—	—	36,905	—	—	36,905
Refinery services operating costs	—	—	30,399	4,212	(3,463)	31,148
Pipeline transportation operating costs	—	—	8,172	211	—	8,383
General and administrative	—	—	14,696	—	—	14,696
Depreciation and amortization	—	—	19,851	640	—	20,491
Total costs and expenses	—	—	982,192	5,063	(3,463)	983,792
OPERATING INCOME	—	—	25,500	5,758	(1)	31,257
Equity in earnings of subsidiaries	35,214	—	1,796	—	(37,010)	—
Equity in earnings of equity investees	—	—	4,922	—	—	4,922
Interest (expense) income, net	(14,066)	—	3,932	(3,935)	—	(14,069)
Income before income taxes	21,148	—	36,150	1,823	(37,011)	22,110
Income tax expense	—	—	(890)	(72)	—	(962)
NET INCOME	$21,148	$ —	$35,260	$ 1,751	$(37,011)	$21,148

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Unaudited Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2015

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Pipeline transportation services	$—	$ —	$27,792	$ 12,257	$—	$40,049
Refinery services	—	—	90,591	7,971	(6,114)	92,448
Marine transportation	—	—	119,965	—	—	119,965
Supply and logistics	—	—	930,722	—	—	930,722
Total revenues	—	—	1,169,070	20,228	(6,114)	1,183,184
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	912,064	—	—	912,064
Marine transportation costs	—	—	66,880	—	—	66,880
Refinery services operating costs	—	—	51,300	7,645	(6,083)	52,862
Pipeline transportation operating costs	—	—	13,455	341	—	13,796
General and administrative	—	—	28,053	—	—	28,053
Depreciation and amortization	—	—	54,045	1,285	—	55,330
Total costs and expenses	—	—	1,125,797	9,271	(6,083)	1,128,985
OPERATING INCOME	—	—	43,273	10,957	(31)	54,199
Equity in earnings of subsidiaries	88,184	—	3,486	—	(91,670)	—
Equity in earnings of equity investees	—	—	34,180	—	—	34,180
Interest (expense) income, net	(37,079)	—	7,601	(7,642)	—	(37,120)
Other income/(expense), net	(19,225)	—	1,696	—	—	(17,529)
Income before income taxes	31,880	—	90,236	3,315	(91,701)	33,730
Income tax expense	—	—	(1,934)	84	—	(1,850)
NET INCOME	$31,880	$ —	$88,302	$ 3,399	$(91,701)	$31,880

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Unaudited Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2014

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Pipeline transportation services	$—	$ —	$31,477	$ 12,635	$—	$44,112
Refinery services	—	—	103,424	10,645	(7,075)	106,994
Marine transportation	—	—	112,241	—	—	112,241
Supply and logistics	—	—	1,771,421	—	—	1,771,421
Total revenues	—	—	2,018,563	23,280	(7,075)	2,034,768
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	1,748,749	—	—	1,748,749
Marine transportation costs	—	—	72,679	—	—	72,679
Refinery services operating costs	—	—	61,990	10,058	(7,705)	64,343
Pipeline transportation operating costs	—	—	15,408	453	—	15,861
General and administrative	—	—	26,706	—	—	26,706
Depreciation and amortization	—	—	38,511	1,260	—	39,771
Total costs and expenses	—	—	1,964,043	11,771	(7,705)	1,968,109
OPERATING INCOME	—	—	54,520	11,509	630	66,659
Equity in earnings of subsidiaries	77,793	—	3,572	—	(81,365)	—
Equity in earnings of equity investees	—	—	12,740	—	—	12,740
Interest (expense) income, net	(26,870)	—	7,898	(7,901)	—	(26,873)
Income before income taxes	50,923	—	78,730	3,608	(80,735)	52,526
Income tax benefit (expense)	—	—	(1,477)	(126)	—	(1,603)
NET INCOME	$50,923	$ —	$77,253	$ 3,482	$(80,735)	$50,923

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unaudited Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2015

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$(30,856)	$ —	$145,231	$ 2,233	$(45,506)	$71,102
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(240,646)	—	—	(240,646)
Cash distributions received from equity investees - return of investment	71,787	—	11,490	—	(71,787)	11,490
Investments in equity investees	(197,722)	—	(1,750)	—	197,722	(1,750)
Repayments on loan to non-guarantor subsidiary	—	—	2,692	—	(2,692)	—
Proceeds from asset sales	—	—	2,228	—	—	2,228
Other, net	—	—	(729)	—	—	(729)
Net cash provided by (used) in investing activities	(125,935)	—	(226,715)	—	123,243	(229,407)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	550,500	—	—	—	—	550,500
Repayments on senior secured credit facility	(515,700)	—	—	—	—	(515,700)
Proceeds from issuance of senior unsecured notes	400,000	—	—	—	—	400,000
Repayment of senior unsecured notes	(350,000)	—	—	—	—	(350,000)
Debt issuance costs	(8,418)	—	—	—	—	(8,418)
Issuance of common units for cash, net	197,722	—	197,722	—	(197,722)	197,722
Distributions to partners/owners	(117,316)	—	(117,316)	—	117,316	(117,316)
Other, net	—	—	774	(2,669)	2,669	774
Net cash provided by (used in) financing activities	156,788	—	81,180	(2,669)	(77,737)	157,562
Net (decrease) increase in cash and cash equivalents	(3)	—	(304)	(436)	—	(743)
Cash and cash equivalents at beginning of period	9	—	8,310	1,143	—	9,462
Cash and cash equivalents at end of period	$6	$ —	$8,006	$ 707	$—	$8,719

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unaudited Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2014

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$(175,807)	$ —	$351,163	$ 2,672	$(72,831)	$105,197
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(240,994)	—	—	(240,994)
Cash distributions received from equity investees - return of investment	23,385	—	6,173	—	(23,385)	6,173
Investments in equity investees	—	—	(14,826)	—	—	(14,826)
Repayments on loan to non-guarantor subsidiary	—	—	2,433	—	(2,433)	—
Proceeds from asset sales	—	—	133	—	—	133
Other, net	—	—	(2,635)	—	—	(2,635)
Net cash used in investing activities	23,385	—	(249,716)	—	(25,818)	(252,149)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,181,200	—	—	—	—	1,181,200
Repayments on senior secured credit facility	(1,271,800)	—	—	—	—	(1,271,800)
Proceeds from issuance of senior unsecured notes	350,000	—	—	—	—	350,000
Debt issuance costs	(10,752)	—	—	—	—	(10,752)
Issuance of common units for cash, net	—	—	—	—	—	—
Distributions to partners/owners	(96,236)	—	(96,236)	—	96,236	(96,236)
Other, net	—	—	—	(2,413)	2,413	—
Net cash provided by (used in) financing activities	152,412	—	(96,236)	(2,413)	98,649	152,412
Net (decrease) increase in cash and cash equivalents	(10)	—	5,211	259	—	5,460
Cash and cash equivalents at beginning of period	20	—	8,050	796	—	8,866
Cash and cash equivalents at end of period	$10	$ —	$13,261	$ 1,055	$—	$14,326

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

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying notes included in this Quarterly Report on Form 10-Q. The following information and such Unaudited Condensed Consolidated Financial Statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations, included in our Annual Report on Form 10-K for the year ended December 31, 2014.

Included in Management's Discussion and Analysis are the following sections:

- Overview
- Segment Reporting Change
- Financial Measures
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Forward Looking Statements

Overview

We reported net income of $11.7 million, or $0.12 per common unit, during the three months ended June 30, 2015 ("2015 Quarter") compared to net income of $21.1 million or $0.24 per common unit, during the three months ended June 30, 2014 ("2014 Quarter").

Available Cash before Reserves was $68.8 million for the 2015 Quarter, an increase of $13.3 million, or 24%, from the 2014 Quarter. See "Financial Measures" below for additional information on Available Cash before Reserves.

Segment Margin (as described below in "Financial Measures") was $98.6 million for the 2015 Quarter, an increase of $15.9 million, or 19%, from the 2014 Quarter.

The increase in our Segment Margin resulted primarily from increases attributable to our offshore pipeline transportation and marine transportation segments of $13.7 million, and $8.2 million, respectively. These increases, as discussed in more detail below and partially offset by smaller decreases in onshore pipeline transportation, refinery services and supply and logistics segment margin, are primarily related to assets recently acquired. Those acquisitions similarly benefited Available Cash before Reserves and net income.

The above factors benefiting net income were partially offset by increases in depreciation and amortization expenses as a result of the effect of recently acquired and constructed assets placed in service, as well as an increase in interest expense due to an increase in our average outstanding indebtedness from recently acquired and constructed assets. In addition, we recognized a $19.2 million loss on debt extinguishment during the 2015 Quarter, relating to the early retirement of our $350 million 7.875% senior unsecured notes due 2018.

A more detailed discussion of our segment results and other costs is included below in "Results of Operations".

Distribution Increase

In July 2015, we declared our fortieth consecutive increase in our quarterly distribution to our common unitholders. Thirty-five of those quarterly increases have been 10% or greater as compared to the same quarter in the preceding year. In August 2015, we will pay a distribution of $0.625 per unit representing a 10.6% increase from our distribution of $0.565 per unit related to the second quarter of 2014.

Acquisition of Offshore Pipelines and Services Business of Enterprise Products Operating, LLC

In July 2015, we acquired the offshore pipeline and services business of Enterprise Products Operating, LLC and its affiliates for approximately $1.5 billion. That business includes assets of approximately 2,350 miles of offshore crude oil and natural gas pipelines and six offshore hub platforms that serve some of the most active drilling and development regions in the United States, including deepwater production fields in the Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. At the closing of that transaction, we entered into transition service agreements to facilitate a smooth transition of operations and uninterrupted services for both employees and customers. That acquisition complements and substantially expands our existing offshore pipelines segment. We expect it to be immediately accretive to Segment Margin and Available Cash before Reserves.

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To finance that transaction, in July, we sold 10,350,000 common units in a public offering that generated proceeds of $437.2 million net of underwriter discounts and $750 million aggregate principal amount of 6.75% senior unsecured notes due 2022 that generated proceeds of $728.6 million net of issuance discount and underwriting fees.

Segment Reporting Change

In the fourth quarter of 2014, we reorganized our operating segments as a result of a change in the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and allocates resources. The results of our marine transportation activities, formerly reported in the Supply and Logistics Segment, are now reported in our Marine Transportation Segment. In addition, the results of our offshore and onshore pipeline transportation activities, formerly reported in the Pipeline Transportation Segment, are now reported separately in our Onshore Pipeline Transportation Segment and our Offshore Pipeline Transportation Segment.

As a result of the above changes, we currently manage our businesses through five divisions that constitute our reportable segments - Onshore Pipeline Transportation, Offshore Pipeline Transportation, Refinery Services, Marine Transportation and Supply and Logistics. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

Financial Measure Reconciliation

For definitions and discussion of the financial measures refer to the "Financial Measures" as later discussed and defined.

Available Cash before Reserves for the periods presented below was as follows:

	Three Months Ended June 30,	
	2015	2014
	(in thousands)	
Net income	$11,665	$21,148
Depreciation and amortization	28,205	20,491
Cash received from direct financing leases not included in income	1,405	1,371
Cash effects of sales of certain assets	460	61
Effects of distributable cash generated by equity method investees not included in income	7,038	7,808
Cash effects of legacy stock appreciation rights plan	(91)	(127)
Non-cash legacy stock appreciation rights plan expense	(468)	322
Expenses related to acquiring or constructing growth capital assets	1,992	418
Unrealized loss (gain) on derivative transactions excluding fair value hedges, net of changes in inventory value	290	2,724
Maintenance capital utilized	(746)	(178)
Non-cash tax expense	642	512
Loss on debt extinguishment	19,225	—
Other items, net	(831)	942
Available Cash before Reserves	$68,786	$55,492

Results of Operations

Revenues and Costs and Expenses

Our revenues for the 2015 Quarter decreased $358.7 million, or 35%, from the 2014 Quarter. Additionally, our costs and expenses decreased $356.8 million, or 36%, between the two periods.

The substantial majority of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products. The significant decrease in our revenues and costs between the two second quarter periods is primarily attributable to a decrease in market prices for crude oil and petroleum products as described below.

The average closing prices for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX") decreased 44% to $57.94 per barrel in the second quarter of 2015, as compared to $103.00 per barrel in the second quarter of 2014.

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In general, we do not expect fluctuations in prices for oil and gas to affect our Segment Margin to the same extent they affect our revenues and costs. We have limited our direct commodity price exposure through the broad use of fee based services contracts, back-to-back purchase and sale arrangements, and hedges. As a result, changes in the price of oil would similarly impact both our revenues and our costs with a disproportionate smaller net impact on our Segment Margin.

Our indirect exposure to the impacts of changes in the price of crude oil are mitigated by our strategy of focusing on customers whose operations tend to be less adversely affected by decreases in the price of crude oil. These customers are refiners and other onshore customers who operate further down the energy value chain (as opposed to producers). Our crude oil pipelines in the Gulf of Mexico represent the single largest departure from our "refinery-centric" customer strategy. The shippers on those pipelines are mostly integrated and large independent energy companies who have developed, and continue to explore for, numerous large-reservoir, long-lived crude oil properties whose production is ideally suited for the vast majority of refineries along the Gulf Coast, unlike the lighter crude oil and condensates produced from numerous onshore shale plays. Those large-reservoir properties and the related pipelines and other infrastructure needed to develop them are capital intensive and yet, we believe, economically viable, in most cases, even in this lower commodity price environment.

Segment Margin

The contribution of each of our segments to total Segment Margin in the three and six months ended June 30, 2015 and June 30, 2014 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Onshore pipeline transportation	$14,363	$16,531	$28,686	$31,220
Offshore pipeline transportation	25,100	11,435	50,298	24,838
Refinery services	20,221	21,627	39,381	42,499
Marine transportation	27,225	18,978	52,918	39,435
Supply and logistics	11,658	14,110	21,405	22,040
Total Segment Margin	$98,567	$82,681	$192,688	$160,032

We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our legacy stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases.

A reconciliation of Segment Margin to Net Income for the periods presented is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Segment Margin	$98,567	$82,681	$192,688	$160,032
Corporate general and administrative expenses	(13,953)	(13,789)	(26,252)	(24,850)
Depreciation and amortization	(28,205)	(20,491)	(55,330)	(39,771)
Interest expense	(17,905)	(14,069)	(37,120)	(26,873)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income (1)	(7,038)	(7,808)	(17,421)	(13,585)
Non-cash items not included in Segment Margin	1,771	(3,043)	(843)	282
Cash payments from direct financing leases in excess of earnings	(1,405)	(1,371)	(2,767)	(2,709)
Loss on debt extinguishment	(19,225)	—	(19,225)	—
Income tax expense	(942)	(962)	(1,850)	(1,603)

Net income	$11,665	$21,148	$31,880	$50,923

(1) Includes distributions attributable to the quarter and received during or promptly following such quarter.

Our reconciliation of Segment Margin to net income reflects that Segment Margin (as defined above) excludes corporate general and administrative expenses, depreciation and amortization, interest expense, certain non-cash items, the most

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significant of which are the non-cash effects of our stock appreciation rights plan and unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. Items in Segment Margin not included in net income are distributable cash from equity investees in excess of equity in earnings (or losses) and cash payments from direct financing leases in excess of earnings.

Onshore Pipeline Transportation Segment

Operating results and volumetric data for our onshore pipeline transportation segment are presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases - onshore crude oil pipelines	$10,195	$10,643	$20,538	$20,888
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	6,113	6,367	12,476	12,874
Sales of onshore crude oil pipeline loss allowance volumes	1,538	3,645	2,603	4,855
Onshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(5,135)	(5,777)	(10,205)	(10,647)
Payments received under direct financing leases not included in income	1,405	1,371	2,767	2,709
Other	247	282	507	541
Segment Margin	$14,363	$16,531	$28,686	$31,220
Volumetric Data (average barrels/day unless otherwise noted):				
Onshore crude oil pipelines:				
Texas	68,407	60,662	71,903	54,769
Jay	18,082	24,337	16,784	26,085
Mississippi	16,824	15,121	15,882	15,150
Louisiana (1)	10,178	22,435	19,975	13,574
Onshore crude oil pipelines total	113,491	122,555	124,544	109,578
CO_2 pipeline (average Mcf/day):				
Free State	167,451	178,500	178,915	185,010

(1) Represents volumes per day from the period the pipeline began operations in the first quarter of 2014.

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Three Months Ended June 30, 2015 Compared with Three Months Ended June 30, 2014

Onshore Pipeline Transportation Segment Margin for the 2015 Quarter decreased $2.2 million, or 13%. The significant components and details of this change were as follows:

- Onshore crude oil pipeline loss allowance volumes, collected and sold, resulted in a decrease in segment margin quarter over quarter of $2.1 million. This decrease is primarily due to the change in the market price of crude oil between the respective periods. Due to the nature of our tariffs on the Louisiana system, we do not collect or sell pipeline loss allowance volumes on that system.
- With respect to our onshore crude oil pipelines, tariff revenues decreased slightly by $0.4 million quarter to quarter, primarily due to a net decrease in throughput volumes of 9,064 barrels per day. This was primarily the result of decreased volumes on our Jay and Louisiana pipeline systems. These decreases were partially offset by volume variances on our other onshore pipeline systems. Due to a mix of tariff rates on our onshore pipelines, the impact on onshore crude oil tariffs and revenues from these volume variances largely offset each other. As our Baton Rouge growth projects become completed and operational, we anticipate a ramp up in volumes on our Louisiana pipeline system in future periods.
- Although volumes on our Free State CO_2 pipeline system decreased 11,049 Mcf per day, or 6%, in the 2015 Quarter as compared to the 2014 Quarter, that decrease did not materially affect contributions to Segment Margin by that pipeline. We provide transportation services on our Free State CO_2 pipeline system through an “incentive” tariff which provides that the average rate per Mcf that we charge during any month decreases as our aggregate throughput for that month increases above specific thresholds. As a result of this "incentive" tariff, fluctuations in volumes above a base level on our Free State CO_2 pipeline system have a limited impact on Segment Margin.

Six Months Ended June 30, 2015 Compared with Six Months Ended June 30, 2014

Onshore Pipeline Transportation Segment Margin for the first six months of 2015 decreased $2.5 million, or 8%. The significant components and details of this change were as follows:

- Onshore crude oil pipeline loss allowance volumes, collected and sold, resulted in a decrease in segment margin quarter over quarter of $2.3 million. This decrease is primarily due to the change in the market price of crude oil between the respective periods. Due to the nature of our tariffs on the Louisiana system, we do not collect or sell pipeline loss allowance volumes on that system.
- With respect to our onshore crude oil pipelines, tariff revenues decreased slightly by $0.4 million quarter to quarter, despite an overall net increase in throughput volumes of 14,966 barrels per day, which was primarily the result of increased volumes on our Texas and Louisiana pipeline systems. These increases were partially offset by volume variances on our other onshore pipeline systems. These variances include a decrease in volumes on our Jay pipeline system, which is primarily attributable to a decrease in volumes entering the pipeline through our Walnut Hill rail facility. Due to a mix of tariff rates on our onshore pipelines, the impact on onshore crude oil tariffs and revenues from these volume variances largely offset each other.
- Although volumes on our Free State CO_2 pipeline system decreased 6,095 Mcf per day, or 3%, in the first six months of 2015 as compared to the first six months of 2014, that decrease did not materially affect contributions to Segment Margin by that pipeline. We provide transportation services on our Free State CO_2 pipeline system through an “incentive” tariff which provides that the average rate per Mcf that we charge during any month decreases as our aggregate throughput for that month increases above specific thresholds. As a result of this "incentive" tariff, fluctuations in volumes above a base level on our Free State CO_2 pipeline system have a limited impact on Segment Margin.

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Offshore Pipeline Transportation Segment

Operating results and volumetric data for our offshore pipeline transportation segment are presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Offshore Pipeline Transportation Segment Margin(1)	$25,100	$11,435	$50,298	$24,838
Volumetric Data 100% basis (average barrels/day unless otherwise noted):				
Offshore crude oil pipelines:				
CHOPS	166,735	169,371	169,382	180,288
Poseidon	274,517	201,190	251,913	206,074
Odyssey	51,165	40,492	49,872	42,735
GOPL (2)	18,709	4,197	12,493	5,814
SEKCO (3)	70,422	—	46,265	—
Offshore crude oil pipelines total	581,548	415,250	529,925	434,911
Volumetric Data net to our ownership interest (average barrels/day unless otherwise noted):				
Offshore crude oil pipelines:				
CHOPS	83,368	84,686	84,691	90,144
Poseidon	76,865	56,333	70,536	57,701
Odyssey	14,838	11,743	14,463	12,393
GOPL (2)	18,709	4,197	12,493	5,814
SEKCO (3)	35,211	—	23,133	—
Offshore crude oil pipelines total	228,991	156,959	205,316	166,052

(1) Offshore Pipeline Transportation segment margin includes approximately $25 million and $50 million of distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting for the three months and six months ended June 30, 2015, respectively. Segment Margin for the three months and six months ended June 30, 2014 include $12 million and $25 million in similar distributions from our offshore pipeline joint ventures, respectively.

(2) Includes 100% of our undivided joint interest ownership in GOPL.

(3) Our SEKCO pipeline was completed in June of 2014. Under the terms of SEKCO's transportation arrangements, its shippers commenced making minimum monthly payments at that time, even though they did not commence throughput of crude until January 2015. Volumes reported for the six months ended June 30, 2015 for SEKCO reflect the gradual commencement of throughput beginning in January of 2015.

Three Months Ended June 30, 2015 Compared with Three Months Ended June 30, 2014

Offshore Pipeline Transportation Segment Margin for the 2015 Quarter increased $13.7 million, or 120%, from the 2014 Quarter. This increase is primarily attributable to the SEKCO pipeline, our 50/50 joint venture with Enterprise Products, being completed and earning certain minimum fees and commencing throughput of crude in January 2015. While throughput has commenced on the SEKCO pipeline, throughput volumes did not exceed a level at which throughput revenues would exceed the monthly minimum payments until the midpoint of the 2015 Quarter. Our SEKCO pipeline is connected to our Poseidon pipeline, so increases in throughput volumes on our SEKCO pipeline have a similar impact on throughput volumes on our Poseidon pipeline. Volume variances on our offshore pipeline systems excluding SEKCO and Poseidon largely offset each other.

Six Months Ended June 30, 2015 Compared with Six Months Ended June 30, 2014

Offshore Pipeline Transportation Segment Margin for the first six months of 2015 increased $25.5 million, or 103%, from the first six months of 2014. This increase is primarily attributable to the SEKCO pipeline, our 50/50 joint venture with Enterprise Products, being completed and earning certain minimum fees and commencing throughput of crude in January 2015. While throughput has commenced on the SEKCO pipeline, throughput volumes did not exceed a level at which throughput

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revenues would exceed the monthly minimum payments until the midpoint of the 2015 Quarter. Our SEKCO pipeline is connected to our Poseidon pipeline, so increases in throughput volumes on our SEKCO pipeline have a similar impact on throughput volumes on our Poseidon pipeline. Volume variances on our offshore pipeline systems excluding SEKCO and Poseidon largely offset each other.

Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Volumes sold (in Dry short tons "DST"):				
NaHS volumes	32,503	37,607	64,933	78,509
NaOH (caustic soda) volumes	22,130	24,066	43,316	48,099
Total	54,633	61,673	108,249	126,608
Revenues (in thousands):				
NaHS revenues	$36,082	$41,162	$71,535	$84,270
NaOH (caustic soda) revenues	11,014	12,642	21,888	24,787
Other revenues	1,690	1,748	3,798	3,602
Total external segment revenues	$48,786	$55,552	$97,221	$112,659
Segment Margin (in thousands)	$20,221	$21,627	$39,381	$42,499
Average index price for NaOH per DST (1)	$577	$595	$583	$587
Raw material and processing costs as % of segment revenues	42 %	42 %	42 %	43 %

(1) Source: IHS Chemical

Three Months Ended June 30, 2015 Compared with Three Months Ended June 30, 2014

Refinery services Segment Margin for the 2015 Quarter decreased $1.4 million, or 7%. The significant components and details of this change were as follows:

- NaHS revenues decreased 12% due primarily to a decrease in volumes. That decrease primarily resulted from lower total volumes than the 2014 Quarter attributable to the bankruptcy of one mining customer, reduced sales to a major customer as they work through an atypical ore seam as a result of a landslide, and certain sales foregone as a result of supply interruptions at one of our major processing facilities.
- We were able to realize benefits from our favorable management of the purchasing (including economies of scale) and utilization of caustic soda in our (and our customers') operations and our logistics management capabilities, which somewhat offset the effects on Segment Margin of decreased NaHS sales volumes.
- Caustic soda revenues decreased 13% primarily due to a reduction in our sales volumes, as well as a decrease in our sales price for caustic soda. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities.
- Average index prices for caustic soda decreased to $577 per DST in the 2015 Quarter compared to $595 per DST during the 2014 Quarter. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic soda on our operating costs.

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Six Months Ended June 30, 2015 Compared with Six Months Ended June 30, 2014

Refinery services Segment Margin for the first six months of 2015 decreased $3.1 million, or 7%. The significant components and details of this change were as follows:

- NaHS revenues decreased 15% primarily due to a decrease in volumes. That decrease primarily resulted from lower total volumes than the year earlier period attributable to the bankruptcy of one mining customer, reduced sales to a major customer as they work through an atypical ore seam as a result of a landslide, and certain sales foregone as a result of supply interruptions at one of our major processing facilities. Additionally, timing of certain bulk deliveries to our South American customers was a factor in decreased volumes for the six months ended between June 30, 2015 and June 30, 2014.
- We were able to realize benefits from our favorable management of the purchasing (including economies of scale) and utilization of caustic soda in our (and our customers') operations and our logistics management capabilities, which somewhat offset the effects on Segment Margin of decreased NaHS sales volumes.
- Caustic soda revenues decreased 12% due to a reduction in our sales volumes, as well as a decrease in our sales price for caustic soda. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities.
- Average index prices for caustic soda decreased to $583 per DST in the first six months of 2015 compared to $587 per DST during the first six months of 2014. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic soda on our operating costs.

Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 71 barges (62 inland and 9 offshore) with a combined transportation capacity of 2.6 million barrels, 36 push/tow boats (27 inland and 9 offshore), and a 330,000 barrel ocean going tanker, the M/T American Phoenix. Operating results for our marine transportation segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues (in thousands):				
Inland freight revenues	$24,612	$22,574	$47,997	$44,297
Offshore freight revenues	25,670	18,805	50,278	38,761
Other rebill revenues (1)	12,312	14,569	21,690	29,183
Total segment revenues	$62,594	$55,948	$119,965	$112,241
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	$35,369	$36,970	$67,047	$72,806
Segment Margin (in thousands)	$27,225	$18,978	$52,918	$39,435
Fleet Utilization: (2)				
Inland Barge Utilization	99.4 %	97.4 %	97.8 %	98.0 %
Offshore Barge Utilization	99.7 %	99.8 %	99.8 %	99.9 %

(1) Under certain of our marine contracts, we "rebill" our customers for a portion of our operating costs.
(2) Utilization rates are based on a 365 day year, as adjusted for planned downtime and drydocking.

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Three Months Ended June 30, 2015 Compared with Three Months Ended June 30, 2014

Marine Transportation Segment Margin for the 2015 Quarter increased $8.2 million, or 43%, from the 2014 Quarter. This increase in Segment Margin in 2015 is primarily due to a full quarter of operating results from the M/T American Phoenix (included as part of our offshore marine fleet), which we acquired in November 2014, two additional barges added to our inland fleet, and higher realized contract rates on several of our oceangoing barges.

Utilization rates on both our inland and offshore barge fleets did not change significantly between the respective quarters. The decrease in operating costs, a large portion of which relate to fuel and other rebillable charges, was largely offset by the decrease in other rebill revenues.

Six Months Ended June 30, 2015 Compared with Six Months Ended June 30, 2014

Marine Transportation Segment Margin for the first six months of 2015 increased $13.5 million, or 34%, from the first six months of 2014. This increase in Segment Margin in 2015 is primarily due to two full quarters of operating results from the M/T American Phoenix (included as part of our offshore marine fleet), which we acquired in November 2014, two additional barges added to our inland fleet, and higher realized contract rates on several of our oceangoing barges.

Utilization rates on both our inland and offshore barge fleets did not change significantly between the respective quarters. The decrease in operating costs, a large portion of which relate to fuel and other rebillable charges, was largely offset by the decrease in other rebill revenues.

Supply and Logistics Segment

Our supply and logistics segment is focused on utilizing our knowledge of the crude oil and petroleum markets to provide oil and gas producers, refineries and other customers with a full suite of services. Our supply and logistics segment owns or leases trucks, terminals, gathering pipelines, railcars, and rail loading and unloading facilities. It uses those assets, together with other modes of transportation owned by third parties and us, to service its customers and for its own account. These services include:

- utilizing the fleet of trucks, trailers and railcars owned or leased by our supply and logistics segment to transport products (primarily crude oil and petroleum products) for customers;
- utilizing various modes of transportation owned by third parties and us to transport products (primarily crude oil and petroleum products) for our own account to take advantage of logistical opportunities primarily in the Gulf Coast states and waterways;
- purchasing/selling and/or transporting crude oil from the wellhead to markets for ultimate use in refining;
- supplying petroleum products (primarily fuel oil, asphalt and other heavy refined products) to wholesale markets;
- purchasing products from refiners, transporting the products to one of our terminals and blending the products to a quality that meets the requirements of our customers and selling those products;
- railcar loading and unloading activities at our crude-by-rail terminals; and
- industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture.

We also use our terminal facilities to take advantage of contango market conditions, for crude oil gathering and marketing, and to capitalize on regional opportunities which arise from time to time for both crude oil and petroleum products.

Despite crude oil being considered a somewhat homogeneous commodity, many refiners are very particular about the quality of crude oil feedstock they process. Many U.S. refineries have distinct configurations and product slates that require crude oil with specific characteristics, such as gravity and sulfur content, among others. The refineries evaluate the costs to obtain, transport and process their preferred feedstocks. That particularity provides us with opportunities to help the refineries in our areas of operation identify crude oil sources meeting their requirements and to purchase the crude oil and transport it to the refineries for sale. The imbalances and inefficiencies relative to meeting the refiners' requirements can provide opportunities for us to utilize our skills and assets to meet their demands. The pricing in the majority of our purchase contracts contains a market price component and a deduction to cover the cost of transporting the crude oil and to provide us with a margin. Contracts sometimes contain a grade differential which considers the composition of the crude oil and its appeal to different customers. Typically, the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

In our petroleum products marketing operations, we supply primarily fuel oil, asphalt and other heavy refined products to wholesale markets. We also provide a service to refineries by purchasing “heavier” petroleum products that are the residual fuels from gasoline production, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers.

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We utilize our fleet of trucks, trailers, railcars, and leased and owned storage capacity to service our crude oil and refining customers and to store and blend the intermediate and finished refined products.

Operating results from our supply and logistics segment were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Supply and logistics revenue	$527,218	$883,108	$930,722	$1,771,421
Crude oil and petroleum products costs, excluding unrealized gains and losses from derivative transactions	(491,836)	(841,547)	(860,691)	(1,694,589)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(23,926)	(27,658)	(48,835)	(54,594)
Other	202	207	209	(198)
Segment Margin	$11,658	$14,110	$21,405	$22,040
Volumetric Data (average barrels per day):				
Crude oil and petroleum products sales:				
Total crude oil and petroleum products sales	100,054	96,443	97,148	98,631
Rail load/unload volumes [1]	18,709	28,356	17,067	27,488

(1) Indicates total barrels for which fees were charged for either loading or unloading at all rail facilities.

Three Months Ended June 30, 2015 Compared with Three Months Ended June 30, 2014

Segment Margin for our supply and logistics segment decreased by $2.5 million, or 17% between the two three month periods.

In the 2015 Quarter, the decrease in our Segment Margin is primarily due to lower crude oil volumes unloaded at our Natchez Terminal and our Port Hudson terminal relative to the 2014 Quarter, as we prepare for the increased utilization of different components of our Baton Rouge facilities.

Six Months Ended June 30, 2015 Compared with Six Months Ended June 30, 2014

Segment Margin for our supply and logistics segment decreased by $0.6 million, or 3% between the first six months of 2015 and the first six months of 2014.

In the six months ended June 30, 2015, the decrease in our Segment Margin is primarily due to lower crude oil volumes unloaded at our Natchez Terminal and our Port Hudson terminal relative to the 2014 quarter, as we prepare for the increased utilization of different components of our Baton Rouge facilities. These decreases were partially offset by improvements in our heavy fuel oil business. These improvements included a reduction in volumes and related infrastructure in our refined products business as we continue to "right size" our heavy fuel oil business to match the lower volumes of blend materials currently available for us to economically handle compared to the volumes that have historically been available to us. This new market reality has resulted, primarily, from the general lightening of refineries' crude slates resulting in a better supply/demand balance between heavy refined bottoms and domestic coker and asphalt requirements.

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Other Costs, Interest, and Income Taxes

General and administrative expenses

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below:				
Corporate	$10,643	$11,147	$20,314	$18,897
Segment	874	892	1,779	1,822
Equity-based compensation plan expense	1,323	2,239	3,551	4,785
Third party costs related to business development activities and growth projects	1,992	418	2,409	1,202
Total general and administrative expenses	$14,832	$14,696	$28,053	$26,706

Total general and administrative expenses increased $0.1 million and $1.3 million between the three and six month periods primarily due to higher third party costs related to business development and growth activities.

Depreciation and amortization expense

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in thousands)		(in thousands)	
Depreciation expense	$22,512	$16,409	$44,549	$31,686
Amortization of intangible assets	4,154	3,147	8,191	6,292
Amortization of CO2 volumetric production payments	1,539	935	2,590	1,793
Total depreciation and amortization expense	$28,205	$20,491	$55,330	$39,771

Total depreciation and amortization expense increased $7.7 million and $15.6 million between the three and six month periods primarily as a result of placing recently acquired and constructed assets in service during calendar 2014 and the first six months of 2015. Depreciation expense increased $6.1 million and $12.9 million between the three and six month periods, primarily as a result of the acquisition of the M/T American Phoenix (included as part of our offshore marine fleet) and recently completed internal growth projects. Amortization of intangible assets increased $1.0 million and $1.9 million between the three and six month periods, as we amortize our intangible assets over the period in which we expect them to contribute to our future cash flows.

Interest expense, net

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in thousands)		(in thousands)	
Interest expense, credit facility (including commitment fees)	$4,019	$4,344	$8,166	$8,172
Interest expense, senior unsecured notes	16,718	14,437	33,562	26,359
Amortization of debt issuance costs and premium	1,303	1,216	2,550	2,320
Capitalized interest	(4,135)	(5,928)	(7,158)	(9,978)
Net interest expense	$17,905	$14,069	$37,120	$26,873

Net interest expense increased $3.8 million and $10.2 million between the three and six month periods primarily due to an increase in our average outstanding indebtedness from recently acquired and constructed assets. In May 2014, we issued an additional $350 million of aggregate principal amount of 5.625% senior unsecured notes to repay borrowings under our senior secured credit facility. Capitalized interest costs decreased $1.8 million and $2.8 million over the three and six month periods primarily due to the completion of construction of the SEKCO pipeline, on which we had incurred capitalized interest cost prior to its completion in June 2014.

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Income tax expense

A portion of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. As a result, a substantial portion of the income tax expense we record relates to the operations of those corporations, and will vary from period to period as a percentage of our income before taxes based on the percentage of our income or loss that is derived from those corporations. The balance of the income tax expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles and foreign income taxes.

Other

Net income for the 2015 Quarter included an unrealized gain on derivative positions, excluding fair value hedges, of $0.2 million. Net income for the 2014 Quarter included an unrealized loss on derivative positions of $2.7 million. Net income for the six months ended June 30, 2015 included an unrealized loss on derivative positions of $1.3 million. Net income for the same period in 2014 included an unrealized gain on derivative positions of $1.2 million. Those amounts are included in supply and logistics product costs in the Unaudited Condensed Consolidated Statements of Operations and are not a component of Segment Margin.

The three and six months ended June 30, 2015, included a loss of approximately $19.2 million that was recognized in relation to the early retirement of our $350 million, 7.875% senior unsecured notes.

Liquidity and Capital Resources

General

As of June 30, 2015, we had $384.2 million of borrowing capacity available under our $1 billion senior secured revolving credit facility. We anticipate that our future internally-generated funds and the funds available under our credit facility will allow us to meet our ordinary course capital needs. Our primary sources of liquidity have been cash flows from operations, borrowing availability under our credit facility and the proceeds from issuances of equity and senior unsecured notes.

Our primary cash requirements consist of:

- Working capital, primarily inventories;
- Routine operating expenses;
- Capital growth and maintenance projects;
- Acquisitions of assets or businesses;
- Payments related to servicing outstanding debt; and
- Quarterly cash distributions to our unitholders.

Capital Resources

Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital from time to time — including through equity and debt offerings (public and private), borrowings under our credit facility and other financing transactions—and to implement our growth strategy successfully. No assurance can be made that we will be able to raise additional capital on satisfactory terms or implement our growth strategy successfully.

On April 10, 2015, we issued 4,600,000 Class A common units in a public offering at a price of $44.42 per unit, which included the exercise by the underwriters of an option to purchase up to 600,000 additional common units from us. We received proceeds, net of underwriting discounts and offering costs, of approximately $198 million from that offering. We used the net proceeds for general partnership purposes, including funding acquisitions (including organic growth projects) or repaying a portion of the borrowings outstanding under our revolving credit facility.

On May 21, 2015, we issued $400 million in aggregate principal amount of 6.0% senior unsecured notes at face value. Interest payments are due on May 15 and November 15 of each year with the initial interest payment due November 15, 2015. Those notes mature on May 15, 2023. We used a portion of the proceeds from those notes to redeem all of our outstanding $350 million, 7.875% senior unsecured notes due 2018. During May 2015, $300.1 million of the $350 million notes outstanding were tendered through the commencement of a cash tender offer. We recognized a loss of approximately $16.7 million in conjunction with the cash tender offer. On June, 20, 2015, the remaining $49.9 million outstanding of the $350 million were redeemed in full and a loss of approximately $2.5 million was recognized due to the early redemption.

At June 30, 2015, long-term debt totaled $1.7 billion, consisting of $585.2 million outstanding under our credit facility (including $43.4 million borrowed under the inventory sublimit tranche), a $350 million carrying amount of senior unsecured

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notes due on February 15, 2021, a $400 million carrying amount of senior unsecured notes due on May 15, 2023 and a $350 million carrying amount of senior unsecured notes due on June 15, 2024.

Cash Flows from Operations

We generally utilize the cash flows we generate from our operations to fund our working capital needs. Excess funds that are generated are used to repay borrowings from our credit facility and/or to fund a portion of our capital expenditures. Our operating cash flows can be impacted by changes in items of working capital, primarily variances in the carrying amount of inventory and the timing of payment of accounts payable and accrued liabilities related to capital expenditures.

We typically sell our crude oil in the same month in which we purchase it, and we do not rely on borrowings under our credit facility to pay for such crude oil purchases, other than inventory. During such periods, our accounts receivable and accounts payable generally move in tandem, as we make payments and receive payments for the purchase and sale of crude oil.

In our petroleum products activities, we buy products, and typically either move the products to one of our storage facilities for further blending or we sell the products within days of our purchase. The cash requirements for these activities can result in short term increases and decreases in our borrowings under our credit facility.

The storage of crude oil and petroleum products can have a material impact on our cash flows from operating activities. In the month we pay for the stored oil or petroleum products, we borrow under our credit facility (or use cash on hand) to pay for the oil or petroleum products, utilizing a portion of our operating cash flows. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil or petroleum products. Additionally, we may be required to deposit margin funds with the NYMEX when prices increase as the value of the derivatives utilized to hedge the price risk in our inventory fluctuates. These deposits also impact our operating cash flows as we borrow under our credit facility or use cash on hand to fund the deposits.

See Note 13 in our Unaudited Condensed Consolidated Financial Statements for information regarding changes in components of operating assets and liabilities for the six months ended June 30, 2015 and June 30, 2014.

The decrease in operating cash flow for the six months ended June 30, 2015 compared to the same period in 2014 was primarily due to increases in working capital needs. As discussed above, changes in the cash requirements related to payment for petroleum products or collection of receivables from the sale of inventory impact the cash provided by operating activities. Additionally, changes in the market prices for crude oil and petroleum products can result in fluctuations in our working capital and, therefore, our operating cash flows between periods as the cost to acquire a barrel of oil or petroleum products will require more or less cash. Net cash flows provided by our operating activities for the six months ended June 30, 2015 were $71.1 million compared to $105.2 million for the six months ended June 30, 2014.

Capital Expenditures and Distributions Paid to our Unitholders

We use cash primarily for our operating expenses, working capital needs, debt service, acquisition activities, internal growth projects and distributions we pay to our unitholders. We finance maintenance capital expenditures and smaller internal growth projects and distributions primarily with cash generated by our operations. We have historically funded material growth capital projects (including acquisitions and internal growth projects) with borrowings under our credit facility, equity issuances and/or the issuance of senior unsecured notes.

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Capital Expenditures and Business and Asset Acquisitions

A summary of our expenditures for fixed assets, business and other asset acquisitions for the six months ended June 30, 2015 and June 30, 2014 is as follows:

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Capital expenditures for fixed and intangible assets:		
Maintenance capital expenditures:		
Onshore pipeline transportation assets	$2,776	$1,119
Offshore pipeline transportation assets	389	900
Refinery services assets	1,411	409
Marine transportation assets	18,968	1,800
Supply and logistics assets	5,206	115
Information technology systems	175	—
Total maintenance capital expenditures	28,925	4,343
Growth capital expenditures:		
Onshore pipeline transportation assets	106,708	26,622
Refinery services assets	39	490
Marine transportation assets	8,694	46,236
Supply and logistics assets	87,420	152,535
Information technology systems	906	358
Total growth capital expenditures	203,767	226,241
Total capital expenditures for fixed and intangible assets	232,692	230,584
Capital expenditures related to equity investees (1)	1,750	12,676
Total capital expenditures	$234,442	$243,260

(1) Amounts represent our investment in the SEKCO pipeline joint venture.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital. We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows.

Growth Capital Expenditures

Total capital expenditures on projects under construction are estimated to be approximately $580 million in 2015 and in future periods, inclusive of expenditures incurred through June 30, 2015. We anticipate that approximately $320 million of that total will be spent in 2015, inclusive of expenditures incurred through June 30, 2015. The most significant of these projects currently under construction are described below.

Wyoming Crude Oil Pipeline

We are constructing a new 60 mile crude oil pipeline to transport crude oil from new receipt point stations in Campbell County and Converse County, Wyoming to our existing Pronghorn Rail Facility. This new crude oil pipeline will have an initial capacity of approximately 30,000 barrels per day and will be supplied by truck volumes and third party gathering infrastructure in the Powder River Basin. We expect this pipeline to become operational in the third quarter of 2015.

Baton Rouge Terminal

We are constructing a new crude oil, intermediates and refined products import/export terminal in Baton Rouge that will be located near the Port of Greater Baton Rouge and will be pipeline-connected to that port's existing deepwater docks on the Mississippi River. We will initially construct approximately 1.1 million barrels of tankage for the storage of crude oil, intermediates and/or refined products with the capability to expand to provide additional terminaling services to our customers. In addition, we will construct a new pipeline from the terminal that will allow for deliveries to existing Exxon Mobil facilities in the area, as well as connect our previously constructed 17 mile line to the terminal allowing for receipts from the Scenic Station Rail Facility. Shippers to Scenic Station will have access to both the local Baton Rouge refining market, as well as the ability to access other attractive refining markets via our

Baton Rouge Terminal. The Baton Rouge Terminal is expected to be operational in the second half of 2015.

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Raceland Rail Facility

The Raceland Rail Facility, a new crude oil unit train unloading facility capable of unloading up to two unit trains per day, which is located in Raceland, Louisiana, and will be connected to existing midstream infrastructure that will provide direct pipeline access to the Louisiana refining markets and is expected to be operational in the second half of 2015.

Inland Marine Barge Transportation Expansion

We ordered 20 new-build barges and 14 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 8 of those barges and 2 of those push boats through December 31, 2014. We accepted delivery of 3 additional push boats in the first half of 2015. We expect to take delivery of those remaining vessels periodically into 2016.

Growth Capital for Acquisition of Enterprise Offshore Pipelines and Services Business

In July 2015, we acquired the offshore pipeline and services business of Enterprise Products Operating, LLC and its affiliates for approximately $1.5 billion. That business includes approximately 2,350 miles of offshore crude oil and natural gas pipelines and six offshore hub platforms that serve some of the most active drilling and development regions in the United States, including deepwater production fields in the Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. At the closing of that transaction, we entered into a transition service agreement with affiliates of Enterprise to facilitate a smooth transition of operations and uninterrupted services for both employees and customers. That acquisition complements and substantially expands our existing offshore pipelines segment. We expect it to be immediately accretive to Segment Margin and Available Cash before Reserves.

To finance that transaction, in July, we sold 10,350,000 common units in a public offering that generated proceeds of $437.2 million net of underwriter discounts and $750 million aggregate principal amount of 6.75% senior unsecured notes due 2022 that generated proceeds of $728.6 million net of issuance discount and underwriting fees.

Maintenance Capital Expenditures

Our increase in maintenance capital expenditures for the six months ended June 30, 2015 primarily relates to construction and new marine push boats to replace older boats. For the six months ended June 30, 2015 we spent approximately $9 million on the construction of those replacement push boats. As we place more assets into service, particularly our marine transportation assets, our maintenance capital expenditures may continue to increase in future years. See further discussion under "Available Cash before Reserves" for how such maintenance capital utilization is reflected in our calculation of Available Cash before reserves.

Distributions to Unitholders

On August 14, 2015, we will pay a distribution of $0.625 per common unit totaling $68.7 million with respect to the second quarter of 2015 to common unitholders of record on July 31, 2015 inclusive of the holders of units issued on April 10, 2015, as well as those issued on July 22, 2015. This is the fortieth consecutive quarter in which we have increased our quarterly distribution. Information on our recent distribution history is included in Note 10 to our Unaudited Condensed Consolidated Financial Statements.

Financial Measures

Segment Margin

We define Segment Margin, which is a "non-GAAP" measure because it is not contemplated by or referenced in accounting principles generally accepted in the U.S., also referred to as GAAP, as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our legacy stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes where relevant and capital investment.

A reconciliation of Segment Margin to net income is included in our segment disclosures in Note 11 to our Unaudited Condensed Consolidated Financial Statements. Our non-GAAP financial measure should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants.

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Available Cash before Reserves

Overview

This Quarterly Report on Form 10-Q includes the financial measure of Available Cash before Reserves, which is a "non-GAAP" measure because it is not contemplated by or referenced in GAAP. Our Non-GAAP measures may not be comparable to similarly titled measures of other companies because such measures may include or exclude other specified items. The accompanying schedule below provides a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure - income from continuing operations. Our non-GAAP financial measures should not be considered (i) as alternatives to GAAP measures of liquidity or financial performance or (ii) as being singularly important in any particular context; they should be considered in a broad context with other quantitative and qualitative information. Our Available Cash before Reserves measures is just one of the relevant data points considered from time to time.

When evaluating our performance and making decisions regarding our future direction and actions (including making discretionary payments, such as quarterly distributions) our board of directors and management team has access to a wide range of historical and forecasted qualitative and quantitative information, such as our financial statements; operational information; various non-GAAP measures; internal forecasts; credit metrics; analyst opinions; performance, liquidity and similar measures; income; cash flow; and expectations for us, and certain information regarding some of our peers. Additionally, our board of directors and management team analyze, and place different weight on, various factors from time to time. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants. We attempt to provide adequate information to allow each individual investor and other external user to reach her/his own conclusions regarding our actions without providing so much information as to overwhelm or confuse such investor or other external user.

Purposes, Uses and Definition

Available Cash before Reserves, also referred to as distributable cash flow, is a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and is commonly used as a supplemental financial measure by management and by external users of financial statements such as investors, commercial banks, research analysts and rating agencies, to aid in assessing, among other things:

(1) the financial performance of our assets;

(2) our operating performance;

(3) the viability of potential projects, including our cash and overall return on alternative capital investments as compared to those of other companies in the midstream energy industry;

(4) the ability of our assets to generate cash sufficient to satisfy certain non-discretionary cash requirements, including interest payments and certain maintenance capital requirements; and

(5) our ability to make certain discretionary payments, such as distributions on our units, growth capital expenditures, certain maintenance capital expenditures and early payments of indebtedness.

We define Available Cash before Reserves as net income as adjusted for specific items, the most significant of which are the addition of certain non-cash expenses (such as depreciation and amortization), the substitution of distributable cash generated by our equity investees in lieu of our equity income attributable to our equity investees (includes distributions attributable to the quarter and received during or promptly following such quarter), the elimination of gains and losses on asset sales (except those from the sale of surplus assets), unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes, the elimination of expenses related to acquiring or constructing assets that provide new sources of cash flows and the subtraction of maintenance capital utilized, which is described in detail below.

Recent Change in Circumstances and Disclosure Format

We have implemented a modified format relating to maintenance capital requirements because of our expectation that our future maintenance capital expenditures may change materially in nature (discretionary vs. non-discretionary), timing and amount from time to time. We believe that, without such modified disclosure, such changes in our maintenance capital expenditures could be confusing and potentially misleading to users of our financial information, particularly in the context of the nature and purposes of our Available Cash before Reserves measure. Our modified disclosure format provides those users with new information in the form of our maintenance capital utilized measure (which we deduct to arrive at Available Cash before Reserves). Our maintenance capital utilized measure constitutes a proxy for non-discretionary maintenance capital expenditures and it takes into consideration the relationship among maintenance capital expenditures, operating expenses and depreciation from period to period.

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Maintenance Capital Requirements

MAINTENANCE CAPITAL EXPENDITURES

Maintenance capital expenditures are capitalized costs that are necessary to maintain the service capability of our existing assets, including the replacement of any system component or equipment which is worn out or obsolete. Maintenance capital expenditures can be discretionary or non-discretionary, depending on the facts and circumstances. Historically, substantially all of our maintenance capital expenditures have been (a) related to our pipeline assets and similar infrastructure, (b) non-discretionary in nature and (c) immaterial in amount as compared to our Available Cash before Reserves measure. Those historical expenditures were non-discretionary (or mandatory) in nature because we had very little (if any) discretion as to whether or when we incurred them. We had to incur them in order to continue to operate the related pipelines in a safe and reliable manner and consistently with past practices. If we had not made those expenditures, we would not have been able to continue to operate all or portions of those pipelines, which would not have been economically feasible. An example of a non-discretionary (or mandatory) maintenance capital expenditure would be replacing a segment of an old pipeline because one can no longer operate that pipeline safely, legally and/or economically in the absence of such replacement.

Prospectively, we believe a substantial amount of our maintenance capital expenditures from time to time will be (a) related to our assets other than pipelines, such as our marine vessels, trucks and similar assets, (b) discretionary in nature and (c) potentially material in amount as compared to our Available Cash before Reserves measure. Those future expenditures will be discretionary (or non-mandatory) in nature because we will have significant discretion as to whether or when we incur them. We will not be forced to incur them in order to continue to operate the related assets in a safe and reliable manner. If we chose not make those expenditures, we would be able to continue to operate those assets economically, although in lieu of maintenance capital expenditures, we would incur increased operating expenses, including maintenance expenses. An example of a discretionary (or non-mandatory) maintenance capital expenditure would be replacing an older marine vessel with a new marine vessel with substantially similar specifications, even though one could continue to economically operate the older vessel in spite of its increasing maintenance and other operating expenses.

In summary, as we continue to expand certain non-pipeline portions of our business, we are experiencing changes in the nature (discretionary vs. non-discretionary), timing and amount of our maintenance capital expenditures that merit a more detailed review and analysis than was required historically. Management’s recently increasing ability to determine if and when to incur certain maintenance capital expenditures is relevant to the manner in which we analyze aspects of our business relating to discretionary and non-discretionary expenditures. We believe it would be inappropriate to derive our Available Cash before Reserves measure by deducting discretionary maintenance capital expenditures, which we believe are similar in nature in this context to certain other discretionary expenditures, such as growth capital expenditures, distributions/dividends and equity buybacks. Unfortunately, not all maintenance capital expenditures are clearly discretionary or non-discretionary in nature. Therefore, we developed a new measure, maintenance capital utilized, that we believe is more useful in the determination of Available Cash before Reserves. Our maintenance capital utilized measure, which is described in more detail below, constitutes a proxy for non-discretionary maintenance capital expenditures and it takes into consideration the relationship among maintenance capital expenditures, operating expenses and depreciation from period to period.

MAINTENANCE CAPITAL UTILIZED

We believe our maintenance capital utilized measure is the most useful quarterly maintenance capital requirements measure to use to derive our Available Cash before Reserves measure. We define our maintenance capital utilized measure as that portion of the amount of previously incurred maintenance capital expenditures that we utilize during the relevant quarter, which would be equal to the sum of the maintenance capital expenditures we have incurred for each project/component in prior quarters allocated ratably over the useful lives of those projects/components. Because we have not historically used our maintenance capital utilized measure, our future maintenance capital utilized calculations will reflect the utilization of solely those maintenance capital expenditures incurred since December 31, 2013. Further, we do not have the actual comparable calculations for our prior periods, and we may not have the information necessary to make such calculations for such periods. And, even if we could locate and/or re-create the information necessary to make such calculations, we believe it would be unduly burdensome to do so in

comparison to the benefits derived.
Commitments and Off-Balance Sheet Arrangements
Contractual Obligations and Commercial Commitments
There have been no material changes to the commitments and obligations reflected in our Annual Report on Form 10-K for the year ended December 31, 2014.

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Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under "Contractual Obligations and Commercial Commitments" in our Annual Report on Form 10-K for the year ended December 31, 2014, nor do we have any debt or equity triggers based upon our unit or commodity prices.

Forward Looking Statements

The statements in this Quarterly Report on Form 10-Q that are not historical information may be "forward looking statements" as defined under federal law. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions and other such references are forward-looking statements, and historical performance is not necessarily indicative of future performance. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "goal," "intend," "may," "could," "plan," "position," "projection," "strategy," "should" or "will," or the n terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include, among others:

- demand for, the supply of, our assumptions about, changes in forecast data for, and price trends related to crude oil, liquid petroleum, NaHS, caustic soda and CO2, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;
- throughput levels and rates;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and close strategic acquisitions on acceptable terms (including obtaining third-party consents and waivers of preferential rights), develop or construct energy infrastructure assets, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- service interruptions in our pipeline transportation systems and processing operations;
- shutdowns or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, petroleum or other products or to whom we sell such products;
- risks inherent in marine transportation and vessel operation, including accidents and discharge of pollutants;
- changes in laws and regulations to which we are subject, including tax withholding issues, accounting pronouncements, and safety, environmental and employment laws and regulations;
- the effects of production declines and the effects of future laws and government regulation;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of our credit agreement and the indentures governing our notes, which contain various affirmative and negative covenants;
- loss of key personnel;
- cash from operations that we generate could decrease or fail to meet expectations, either of which could reduce our ability to pay quarterly cash distributions at the current level or continue to increase quarterly cash distributions in the future;
- an increase in the competition that our operations encounter;
- cost and availability of insurance;
- hazards and operating risks that may not be covered fully by insurance;
- our financial and commodity hedging arrangements
- changes in global economic conditions, including capital and credit markets conditions, inflation and interest rates;

- natural disasters, accidents or terrorism;

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- changes in the financial condition of customers or counterparties;
- adverse rulings, judgments, or settlements in litigation or other legal or tax matters;
- the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes; and
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2014. These risks may also be specifically described in our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Form 8-K/A and other documents that we may file from time to time with the SEC. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2014. There have been no material changes that would affect the quantitative and qualitative disclosures provided therein. Also, see Note 14 to our Unaudited Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Item 4. Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this Quarterly Report on Form 10-Q is accumulated and communicated to them and our management to allow timely decisions regarding required disclosures.

There were no changes during the period covered by this report that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to this item has been incorporated by reference from our Annual Report on Form 10-K for the year ended December 31, 2014. There have been no material developments in legal proceedings since the filing of such Form 10-K.

Item 1A. Risk Factors

Except as described below, there has been no material change in our risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014, except as supplemented by our Quarterly Reports on Form 10-Q and Periodic Reports on Form 8-K and Form 8-K/A. On July 16, 2015, we filed a Current Report on Form 8-K that, among other things, revised, clarified and supplemented our risk factors, including those contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 (the "Annual Report") as set forth below.

As part of the filing of this Form 10-Q, we intend to revise, clarify and supplement our risk factors, including those contained in the Annual Report. The risk factors below should be considered together with the other risk factors described in the Annual Report and filings with the SEC under the Securities Exchange Act of 1934, as amended, after the Annual Report. For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2014, as well as any risk factors contained in other filings with the SEC, including Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Form 8-K/A and other documents that we may file from time to time with the SEC.

As a result of the additional indebtedness incurred to consummate the Enterprise Offshore Business Acquisition, we may experience a potential material adverse effect on our financial condition and results of operations.

We financed the Enterprise Offshore Business Acquisition with the net proceeds from debt or equity financing and borrowings under our revolving credit facility.

Our increased indebtedness could also have adverse consequences on our business, such as:

- requiring us to use a substantial portion of our cash flow from operations to service our indebtedness, which would reduce the available cash flow to fund working capital, capital expenditures, development projects and other general partnership purposes and reduce cash available for distributions;
- limiting our ability to obtain additional financing to fund our working capital needs, acquisition, capital expenditures or other debt service requirements or for other purposes;
- increasing the costs of incurring additional debt;
- limiting our ability to compete with other companies that are not as highly leveraged, as we may be less capable of responding to adverse economic and industry conditions;
- restricting the way in which we conduct our business because of financial and operating covenants in the agreements governing our existing and future indebtedness;
- exposing us to potential events of default (if not cured or waived) under covenants contained in our debt instruments that could have a material adverse effect on our business, financial condition and operating results; and
- limiting our ability to react to changing market conditions in our industry

The impact of any of these potential adverse consequences could have a material adverse effect on our results of operations, financial condition and liquidity.

As a result of the Enterprise Offshore Business Acquisition, we anticipate that the scope and size of our operations and business will substantially change. We cannot provide assurance that our expansion in scope and size will be successful.

We anticipate that the Enterprise Offshore Business Acquisition will substantially expand the scope and size of our business by adding substantial offshore operations to our existing offshore business. The anticipated future growth of our business will impose significant added responsibilities on management, including the need to identify, recruit, train and integrate additional employees. Our senior management's attention may be diverted from the management of daily operations to the integration of the assets acquired in the Enterprise Offshore Business Acquisition. Our ability to manage our business and growth will require us to continue to improve our operational, financial and management controls, reporting systems and procedures. We may also encounter risks, costs and expenses associated with any undisclosed or other unanticipated liabilities and use more cash and other financial resources on integration and implementation activities than we expect. We may not be able to successfully integrate the Enterprise Offshore Business into our existing operations or realize the expected economic

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benefits of the Enterprise Offshore Business Acquisition, which may have a material adverse effect on our business, financial condition and results of operations, including our distributable cash flow.

Failure to successfully combine our business with the assets acquired in the Enterprise Offshore Business Acquisition, or an inaccurate estimate by us of the benefits to be realized from the Enterprise Offshore Business Acquisition, may adversely affect our future results.

The Enterprise Offshore Business Acquisition involves potential risks, including:

- the failure to realize expected profitability, growth or accretion;
- environmental or regulatory compliance matters or liabilities;
- title or permit issues;
- the incurrence of significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges; and
- the incurrence of unanticipated liabilities and costs for which indemnification is unavailable or inadequate

The expected benefits from the Enterprise Offshore Business Acquisition may not be realized if our estimates of the potential net cash flows associated with the assets acquired by us in the Enterprise Offshore Business Acquisition are materially inaccurate or if we failed to identify operating issues or liabilities associated with the assets. The accuracy of our estimates of the potential net cash flows attributable to such assets is inherently uncertain.

If any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of the Enterprise Offshore Business Acquisition may not be fully realized, if at all, and our future financial condition, results of operations and distributable cash flow could be negatively impacted.

The tax treatment of publicly traded partnerships could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, affect or cause us to change our business activities, affect the tax considerations of an investment in us and change the character or treatment of portions of our income. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that would adversely affect the tax treatment of certain publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships.

On May 5, 2015, the U.S. Treasury Department and the IRS released proposed regulations (the “Proposed Regulations”) regarding qualifying income under Section 7704(d)(1)(E) of the Code. The U.S. Treasury Department and the IRS have requested comments from industry participants regarding the standards set forth in the Proposed Regulations. The Proposed Regulations provide an exclusive list of industry-specific activities and certain limited support activities that generate qualifying income. Although the Proposed Regulations adopt a narrow interpretation of the activities that generate qualifying income, we believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the Proposed Regulations. However, the Proposed Regulations could be changed before they are finalized and could take a position that is contrary to our interpretation of Section 7704 of the Code. If the regulations in their final form were to treat any material portion of our income we treat as qualifying income as non-qualifying income, we anticipate being able to treat that income as qualifying income for ten years under special transition rules provided in the Proposed Regulations.

We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could cause a material reduction in our anticipated cash flows and could cause us to be treated as an association taxable as a corporation for U.S. federal income tax purposes subjecting us to the entity-level tax and adversely affecting the value of our common units.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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Item 4. Mine Safety Disclosures
Not applicable.
Item 5. Other Information
None.
Item 6. Exhibits.
(a) Exhibits

	2.1	Purchase and Sale Agreement, dated July 16, 2015, by and between Genesis Energy, L.P. and Enterprise Products Operating, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K/A dated July 16, 2015, File No. 001-12295).
	3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 to Registration Statement on Form S-1, File No. 333-11545).
	3.2	Amendment to the Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.2 to Form 10-Q for the quarterly period ended June 30, 2011, File No. 011-12295).
	3.3	Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 3, 2011, File No. 001-12295).
	3.4	Certificate of Conversion of Genesis Energy, Inc. a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009, File No. 001-12295).
	3.5	Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009, File No. 001-12295).
	3.6	Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011, File No. 001-12295).
	4.1	Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2007, File No. 001-12295).
	4.2	Indenture, dated May 21, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K dated May 21, 2015, File No. 001-12295).
	4.3	Supplemental Indenture for 6.000% Senior Notes due 2023, dated as of May 21, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (including the form of the Notes) (incorporated by reference to Exhibit 4.2 to Form 8-K dated May 21, 2015, File No. 001-12295).
*	4.4	Second Supplemental Indenture for 6.000% Senior Notes due 2023, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
*	4.5	Third Supplemental Indenture for 6.000% Senior Notes due 2023, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
*	4.6	Seventh Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
*	4.7	Eighth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.

*	4.8	Eighth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
*	4.9	Ninth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
	4.10	Fourth Supplemental Indenture for 6.75% Senior Notes due 2022, dated as of July 23, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K dated July 28, 2015, File No. 001-12295)

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*	31.1	Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.
*	31.2	Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.
*	32	Certification by Chief Executive Officer and Chief Financial Officer Pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934.
*	101.INS	XBRL Instance Document
*	101.SCH	XBRL Schema Document
*	101.CAL	XBRL Calculation Linkbase Document
*	101.LAB	XBRL Label Linkbase Document
*	101.PRE	XBRL Presentation Linkbase Document
*	101.DEF	XBRL Definition Linkbase Document

* Filed herewith

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SIGNATURES

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

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)

By: GENESIS ENERGY, LLC,
as General Partner

Date: July 29, 2015

By: /s/ ROBERT V. DEERE
Robert V. Deere
Chief Financial Officer