GENESIS ENERGY LP
Form 10-Q
November 03, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2017
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 1-12295

GENESIS ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	76-0513049 (I.R.S. Employer Identification No.)
919 Milam, Suite 2100, Houston, TX (Address of principal executive offices)	77002 (Zip code)

Registrant’s telephone number, including area code: (713) 860-2500

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

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

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

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

Exchange Act.

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

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Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. There were 122,539,221 Class A Common Units and 39,997 Class B Common Units outstanding as of November 3, 2017.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
GENESIS ENERGY, L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except units)

	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,694	$ 7,029
Accounts receivable - trade, net	437,039	224,682
Inventories	98,558	98,587
Other	45,533	29,271
Total current assets	590,824	359,569
FIXED ASSETS, at cost	5,522,292	4,763,396
Less: Accumulated depreciation	(681,900)	(548,532)
Net fixed assets	4,840,392	4,214,864
MINERAL LEASEHOLDS, net	622,756	—
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	127,248	132,859
EQUITY INVESTEES	383,191	408,756
INTANGIBLE ASSETS, net of amortization	187,441	204,887
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	60,736	56,611
TOTAL ASSETS	$ 7,137,634	$ 5,702,592
LIABILITIES AND CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 203,717	$ 119,841
Accrued liabilities	160,294	140,962
Total current liabilities	364,011	260,803
SENIOR SECURED CREDIT FACILITY	1,372,500	1,278,200
SENIOR UNSECURED NOTES, net of debt issuance costs	2,358,049	1,813,169
DEFERRED TAX LIABILITIES	26,399	25,889
OTHER LONG-TERM LIABILITIES	256,462	204,481
Total liabilities	4,377,421	3,582,542
MEZZANINE CAPITAL:		
Series A Convertible Preferred Units, 22,249,494 issued and outstanding at September 30, 2017	691,708	—
PARTNERS' CAPITAL:		
Common unitholders, 122,579,218 and 117,979,218 units issued and outstanding at September 30, 2017 and December 31, 2016, respectively	2,077,393	2,130,331
Noncontrolling interests	(8,888)	(10,281)
Total partners' capital	2,068,505	2,120,050
TOTAL LIABILITIES, MEZZANINE CAPITAL AND PARTNERS' CAPITAL	$ 7,137,634	$ 5,702,592

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 OPERATIONS
(In thousands, except per unit amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES:				
Offshore pipeline transportation services	80,671	89,717	243,437	244,837
Sodium minerals and sulfur services	109,765	45,725	197,879	129,585
Marine transportation	48,534	55,285	152,038	159,930
Onshore facilities and transportation	247,144	269,323	714,974	750,088
Total revenues	486,114	460,050	1,308,328	1,284,440
COSTS AND EXPENSES:				
Onshore facilities and transportation product costs	202,047	230,229	582,535	620,620
Onshore facilities and transportation operating costs	23,982	22,476	80,160	71,974
Marine transportation operating costs	35,789	38,490	111,980	105,942
Sodium minerals and sulfur services operating costs	79,365	25,077	133,335	67,641
Offshore pipeline transportation operating costs	18,690	23,122	54,682	63,732
General and administrative	19,409	11,212	38,723	34,716
Depreciation, depletion and amortization	63,732	54,265	176,453	156,800
Gain on sale of assets	—	—	(26,684)	—
Total costs and expenses	443,014	404,871	1,151,184	1,121,425
OPERATING INCOME	43,100	55,179	157,144	163,015
Equity in earnings of equity investees	13,044	12,488	34,805	35,362
Interest expense	(47,388)	(34,735)	(122,117)	(104,657)
Other expense	(2,276)	—	(2,276)	—
Income before income taxes	6,480	32,932	67,556	93,720
Income tax expense	(320)	(949)	(878)	(2,959)
NET INCOME	6,160	31,983	66,678	90,761
Net loss attributable to noncontrolling interests	152	118	457	370
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$6,312	$32,101	$67,135	$91,131
Less: Accumulated distributions attributable to Series A Convertible Preferred Units	(5,469)	—	(5,469)	—
NET INCOME AVAILABLE TO COMMON UNITHOLDERS	$843	$32,101	$61,666	$91,131
NET INCOME PER COMMON UNIT (Note 10):				
Basic and Diluted	$0.01	$0.28	$0.51	$0.81
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:				
Basic and Diluted	122,579	115,718	121,198	111,906

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	Noncontrolling Interest	Total
Partners' capital, January 1, 2017	117,979	$2,130,331	$ (10,281)	$2,120,050
Net income (loss)	—	67,135	(457)	66,678
Cash distributions to partners	—	(260,586)	—	(260,586)
Cash contributions from noncontrolling interests	—	—	1,850	1,850
Issuance of common units for cash, net	4,600	140,513	—	140,513
Partners' capital, September 30, 2017	122,579	$2,077,393	$ (8,888)	$2,068,505

	Number of Common Units	Partners' Capital	Noncontrolling Interest	Total
Partners' capital, January 1, 2016	109,979	$2,029,101	$ (8,350)	$2,020,751
Net income (loss)	—	91,131	(370)	90,761
Cash distributions to partners	—	(227,454)	—	(227,454)
Issuance of common units for cash, net	8,000	298,051	—	298,051
Partners' capital, September 30, 2016	117,979	$2,190,829	$ (8,720)	$2,182,109

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)

	Nine Months Ended September 30,	
	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$66,678	$90,761
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation, depletion and amortization	176,453	156,800
Provision for leased items no longer in use	12,589	—
Gain on sale of assets	(26,684)	—
Amortization of debt issuance costs and discount	8,154	7,563
Amortization of unearned income and initial direct costs on direct financing leases	(10,374)	(10,856)
Payments received under direct financing leases	15,501	15,501
Equity in earnings of investments in equity investees	(34,805)	(35,362)
Cash distributions of earnings of equity investees	45,854	49,528
Non-cash effect of equity-based compensation plans	(5,524)	6,102
Deferred and other tax liabilities	508	2,058
Unrealized loss on derivative transactions	3,040	742
Other, net	(7,338)	8,967
Net changes in components of operating assets and liabilities (Note 13)	(26,262)	(63,407)
Net cash provided by operating activities	217,790	228,397
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(182,653)	(363,218)
Cash distributions received from equity investees - return of investment	14,517	16,652
Acquisitions	(1,325,759)	(25,394)
Contributions in aid of construction costs	124	12,208
Proceeds from asset sales	39,204	3,303
Other, net	—	185
Net cash used in investing activities	(1,454,567)	(356,264)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on senior secured credit facility	1,247,700	883,600
Repayments on senior secured credit facility	(1,153,400)	(831,600)
Proceeds from issuance of senior unsecured notes	550,000	—
Proceeds from issuance of Series A convertible preferred units, net	729,958	—
Debt issuance costs	(17,808)	(1,578)
Issuance of common units for cash, net	140,513	298,051
Contributions from noncontrolling interests	1,850	—
Distributions to common unitholders	(260,586)	(227,454)
Other, net	1,215	(600)
Net cash provided by financing activities	1,239,442	120,419
Net increase (decrease) in cash and cash equivalents	2,665	(7,448)
Cash and cash equivalents at beginning of period	7,029	10,895
Cash and cash equivalents at end of period	$9,694	$3,447

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 crude oil and natural gas industry in the Gulf Coast region of the United States, Wyoming and the Gulf of Mexico. We have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, soda ash businesses, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks. We 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.
On September 1, 2017, we acquired Tronox Limited's ("Tronox's") trona and trona-based exploring, mining, processing, producing, marketing and selling business (the "Alkali Business") for approximately $1.325 billion in cash. We funded that acquisition and the related transaction costs with proceeds from a $750 million private placement of convertible preferred units, a $550 million public offering of notes, our revolving credit facility, and cash on hand. At the closing, we entered into transition service agreements to facilitate the transition of operations and uninterrupted services for both employees and customers. We will report the results of our Alkali Business in our renamed sodium minerals and sulfur services segment, which will include our Alkali Business as well as our existing refinery services operations.
In the fourth quarter of 2016, we reorganized our operating segments as a result of the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and allocates resources. Due to the increasingly integrated nature of our onshore operations, the results of our onshore pipeline transportation segment, formerly reported under its own segment, is now reported in our onshore facilities and transportation segment. The onshore facilities and transportation segment was formerly named as our supply and logistics segment. This segment was renamed in the second quarter of 2017 to more accurately describe the nature of its operations. These changes are consistent with the increasingly integrated nature of our onshore operations. We will report the results of the Alkali Business in our renamed sodium minerals and sulfur services segment, which will include the Alkali Business as well as our existing refinery services operations.
As a result of the above changes, we currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. Our disclosures related to prior periods have been recast to reflect our reorganized segments.
These four divisions that constitute our reportable segments consist of the following:

- Offshore pipeline transportation and processing of crude oil and natural gas in the Gulf of Mexico;
- Sodium minerals and sulfur services involving trona and trona-based exploring, mining, processing, producing, marketing and selling activities, as well as 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");
- Onshore facilities and transportation, which include terminalling, blending, storing, marketing, and transporting crude oil, petroleum products, and $CO_{2;}$
- Marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America; and

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

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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, 2016.

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. Recent Accounting Developments

Recently Issued

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 transition method. 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. Our process of evaluating the impact of this guidance on each type of revenue contract entered into with customers is ongoing, but nearing completion. This process includes regular involvement from our implementation team in determining any significant impact on accounting treatment, processes, internal controls, and disclosures. While we do not believe there will be a material impact to our revenues upon adoption based on our preliminary assessment, we continue to evaluate the impacts of our pending adoption of this guidance until finalized conclusions are determined, particularly involving contracts within our sodium minerals and sulfur services segment including those within our recently acquired Alkali Business. Though we have not finalized our conclusions, we currently plan to apply the modified retrospective transition approach.

In July 2015, the FASB issued guidance modifying the accounting for inventory. Under this guidance, the measurement principle for inventory will change from lower of cost or market value to lower of cost or net realizable value. The guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The guidance is effective for reporting periods after December 15, 2016, with early adoption permitted. We have adopted this guidance as of January 1, 2017 with no material impact on our consolidated financial statements.

In February 2016, the FASB issued guidance to improve the transparency and comparability among companies by requiring lessees to recognize a lease liability and a corresponding lease asset for virtually all lease contracts. The guidance also requires additional disclosure about leasing arrangements. The guidance is effective for interim and annual periods beginning after December 15, 2018 and requires a modified retrospective approach to adoption. Early adoption is permitted. We are currently evaluating this guidance.

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. ASU 2016-15 addresses how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash flow, and other Topics. ASU 2016-15 is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2017. We do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

3. Acquisition and Divestiture

Acquisition

Alkali Business

On September 1, 2017, we acquired the Alkali Business for approximately $1.325 billion (inclusive of approximately $100 million in working capital). The Alkali Business produces natural soda ash, also known as sodium carbonate (Na_2CO_3), as basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products. To finance that transaction and the related costs, we used proceeds from (i) a $550.0 million public offering of 6.50% senior unsecured notes due 2025 in August 2017, generating net proceeds of $540.1 million after issuance discount and underwriting fees, (ii) a $750 million private placement of Class A Convertible Preferred units in September 2017, generating net proceeds of $726.2 million, (iii) borrowings under our revolving credit facility and (iv) cash on hand.

We have reflected the financial results of our Alkali Business in our sodium minerals and sulfur services segment from the date of acquisition. The purchase price has been allocated to the assets acquired and liabilities assumed based on estimated preliminary fair values. Those preliminary fair values were developed by management with the assistance of a third-party

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valuation firm and are subject to change pending a final valuation report and final determination of working capital acquired and other purchase price adjustments. We expect to finalize the purchase price allocation for this transaction during the fourth quarter of 2017.

The preliminary allocation of the purchase price, as presented on our Consolidated Balance Sheet, is summarized as follows:

Accounts receivable	138,291
Inventories	31,944
Other current assets	13,947
Fixed assets	617,878
Mineral leaseholds	623,137
Accounts payable	(51,534)
Other current liabilities	(29,870)
Other long-term liabilities	(18,793)
Total Purchase Price	$1,325,000

Fixed assets identified in connection with our valuation and preliminary purchase price allocation include the related facilities, machinery and equipment associated with the Alkali Business, principally at our Green River, Wyoming operations. These assets will be depreciated under the straight line method and have an average useful life of approximately 15 years. Mineral leaseholds include the trona reserves at our Green River, Wyoming facility and are depleted over their useful lives as determined by the units of production method. Other long-term liabilities include various items including assumed employee benefit plan obligations.

Our Consolidated Financial Statements include the results of our Alkali Business since September 1, 2017, the 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 September 30, 2017	Nine Months Ended September 30, 2017
Revenues	$ 66,003	66,003
Net income	$ 10,654	10,654

The table below presents selected unaudited pro forma financial information incorporating the historical results of our Alkali Business. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2016 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. This pro forma information was prepared using historical financial data of the Tronox trona and trona-based exploring, mining, processing, producing, marketing and selling business and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Alkali Business acquisition been completed on January 1, 2016. Pro forma net income includes the effects of distributions on preferred units and interest expense on incremental borrowings. The dilutive effect of Series A Preferred Units is calculated using the if-converted method.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Pro forma consolidated financial operating results:				
Revenues	$615,275	$653,749	$1,829,389	$1,872,939
Net Income Attributable to Genesis Energy, L.P.	10,978	31,400	59,314	78,113
Net Income Available to Common Unitholders	(5,276)	15,943	10,939	31,853
Basic and diluted earnings per common unit:				
As reported net income per common unit	$0.01	$0.28	$0.51	$0.81

Pro forma net income per common unit	$(0.04)	$0.14	$0.09	$0.28

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As relating to the Alkali Business acquisition, we have incurred approximately $10.4 million in acquisition related costs through September 30, 2017. Such costs are included as "General and Administrative costs" on our Unaudited Condensed Consolidated Statement of Operations.

4. Inventories

The major components of inventories were as follows:

	September 30, 2017	December 31, 2016
Petroleum products	$ 2,618	$ 11,550
Crude oil	46,035	73,133
Caustic soda	5,381	4,593
NaHS	11,176	9,304
Raw materials - Alkali Operations	4,560	—
Work-in-process - Alkali Operations	4,751	—
Finished goods, net - Alkali Operations	14,197	—
Materials and supplies, net - Alkali Operations	9,840	—
Other	—	7
Total	$ 98,558	$ 98,587

Inventories are valued at the lower of cost or net realizable value. The net realizable value of inventories were not recorded below cost as of September 30, 2017 and December 31, 2016.

5. Fixed Assets and Mineral Leaseholds

Fixed Assets

Fixed assets consisted of the following:

	September 30, 2017	December 31, 2016
Crude oil pipelines and natural gas pipelines and related assets	$ 3,004,618	$ 2,901,202
Alkali facilities, machinery, and equipment	617,878	—
Onshore facilities, machinery, and equipment	757,874	427,658
Transportation equipment	17,995	17,543
Marine vessels	898,582	863,199
Land, buildings and improvements	103,774	55,712
Office equipment, furniture and fixtures	9,681	9,654
Construction in progress	58,069	440,225
Other	53,821	48,203
Fixed assets, at cost	5,522,292	4,763,396
Less: Accumulated depreciation	(681,900)	(548,532)
Net fixed assets	$ 4,840,392	$ 4,214,864

Mineral Leaseholds

Our Mineral Leaseholds, as relating to our recently acquired Alkali Business, consist of the following:

	September 30, 2017
Mineral leaseholds	623,137
Less: Accumulated depletion	(381)
Mineral leaseholds, net	$ 622,756

Our depreciation and depletion expense for the periods presented was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Depreciation expense	$57,117	$46,909	$157,438	$135,428
Depletion Expense	381	—	381	—

Asset Retirement Obligations

We record AROs in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations.

The following table presents information regarding our AROs since December 31, 2016:

ARO liability balance, December 31, 2016	$213,726
Accretion expense	8,257
Change in estimate	7,875
Acquisitions	2,444
Divestitures	(7,649)
Settlements	(21,252)
Other	240
ARO liability balance, September 30, 2017	$203,641

Of the ARO balances disclosed above, $19.3 million and $22.4 million is included as current in "Accrued liabilities" on our Unaudited Condensed Consolidated Balance Sheet as of September 30, 2017 and December 31, 2016, respectively. The remainder of the ARO liability as of September 30, 2017 and December 31, 2016 is included in "Other long-term liabilities" on our Unaudited Condensed Consolidated Balance Sheet.

With respect to our AROs, the following table presents our forecast of accretion expense for the periods indicated:

Remainder of	2017	$2,741
	2018	$9,686
	2019	$8,782
	2020	$9,378
	2021	$10,014

Certain of our unconsolidated affiliates have AROs recorded at September 30, 2017 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our Consolidated Financial Statements.

6. 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 or be less than 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 September 30, 2017 and December 31, 2016, the unamortized excess cost amounts totaled $386.3 million and $398.1 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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Genesis’ share of operating earnings	$16,986	$16,444	$46,631	$47,281
Amortization of excess purchase price	(3,942)	(3,956)	(11,826)	(11,919)
Net equity in earnings	$13,044	$12,488	$34,805	$35,362
Distributions received	$20,180	$21,551	$60,371	$66,180

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

The following tables present the unaudited balance sheet and income statement information (on a 100% basis) for Poseidon Oil Pipeline Company (which is our most significant equity investment):

	September 30, 2017	December 31, 2016
BALANCE SHEET DATA:		
Assets		
Current assets	$ 18,638	$ 17,111
Fixed assets, net	221,123	232,736
Other assets	1,282	861
Total assets	$ 241,043	$ 250,708
Liabilities and equity		
Current liabilities	$ 20,683	$ 20,727
Other liabilities	231,469	219,644
Equity	(11,109)	10,337
Total liabilities and equity	$ 241,043	$ 250,708

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
INCOME STATEMENT DATA:				
Revenues	$30,597	$31,219	$88,003	$90,658
Operating income	$22,334	$23,107	$63,159	$68,166
Net income	$20,739	$21,921	$58,754	$64,670

Poseidon's revolving credit facility

Borrowings under Poseidon’s revolving credit facility, which was amended and restated in February 2015, are primarily used to fund spending on capital projects. The February 2015 credit facility is non-recourse to Poseidon’s owners and secured by substantially all of Poseidon's assets. The February 2015 credit facility contains customary covenants such as restrictions on debt levels, liens, guarantees, mergers, sale of assets and distributions to owners. A breach of any of these covenants could result in acceleration of the maturity date of Poseidon’s debt. Poseidon was in compliance with the terms of its credit agreement for all periods presented in these Unaudited Condensed Consolidated Financial Statements.

GENESIS ENERGY, L.P.
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7. Intangible Assets

The following table summarizes the components of our intangible assets at the dates indicated:

	September 30, 2017			December 31, 2016		
	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Sodium minerals and sulfur services:						
Customer relationships	$94,654	$ 91,809	$2,845	$94,654	$ 89,756	$4,898
Licensing agreements	38,678	35,947	2,731	38,678	34,204	4,474
Segment total	133,332	127,756	5,576	133,332	123,960	9,372
Onshore Facilities & Transportation:						
Customer relationships	35,430	34,731	699	35,430	33,676	1,754
Intangibles associated with lease	13,260	4,815	8,445	13,260	4,459	8,801
Segment total	48,690	39,546	9,144	48,690	38,135	10,555
Marine contract intangibles	27,000	10,350	16,650	27,000	6,300	20,700
Offshore pipeline contract intangibles	158,101	18,029	140,072	158,101	11,788	146,313
Other	28,747	12,748	15,999	28,569	10,622	17,947
Total	$395,870	$ 208,429	$187,441	$395,692	$ 190,805	$204,887

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Amortization of intangible assets	$5,879	$6,122	$17,623	$18,154

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

Remainder of	2017	$5,919
	2018	$21,506
	2019	$17,171
	2020	$16,237
	2021	$10,627

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8. Debt

Our obligations under debt arrangements consisted of the following:

	September 30, 2017			December 31, 2016		
	Principal	Unamortized Discount and Debt Issuance Costs (1)	Net Value	Principal	Unamortized Discount and Debt Issuance Costs (1)	Net Value
Senior secured credit facility	$1,372,500	$ —	$1,372,500	$1,278,200	$ —	$1,278,200
5.750% senior unsecured notes due February 2021	350,000	3,399	346,601	350,000	4,163	345,837
6.750% senior unsecured notes due August 2022	750,000	16,889	733,111	750,000	19,296	730,704
6.000% senior unsecured notes due May 2023	400,000	5,958	394,042	400,000	6,758	393,242
5.625% senior unsecured notes due June 2024	350,000	5,941	344,059	350,000	6,614	343,386
6.500% senior unsecured notes due October 2025	550,000	9,764	540,236	—	—	—
Total long-term debt	$3,772,500	$ 41,951	$3,730,549	$3,128,200	$ 36,831	$3,091,369

(1) Unamortized debt issuance costs associated with our senior secured credit facility (included in Other Long Term Assets on the Unaudited Condensed Consolidated Balance Sheet) were $15.2 million and $10.7 million as of September 30, 2017 and December 31, 2016, respectively.

As of September 30, 2017, we were in compliance with the financial covenants contained in our credit agreement and senior unsecured notes indentures.

Senior Secured Credit Facility

In July 2017, we amended our credit agreement to, among other things, make certain technical amendments related to the financing of our acquisition of the Alkali Business.

The key terms for rates under our $1.7 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 3.00% on Eurodollar borrowings and from 0.50% to 2.00% on alternate base rate borrowings.
- Letter of credit fees range from 1.50% to 3.00%
- The commitment fee on the unused committed amount will range from 0.25% to 0.50%.
- The accordion feature is $300.0 million, giving us the ability to expand the size of the facility to up to $2.0 billion for acquisitions or growth projects, subject to lender consent.

At September 30, 2017, we had $1.4 billion borrowed under our $1.7 billion credit facility, with $38.7 million of the borrowed amount designated as a loan under the inventory sublimit. Our credit agreement allows up to $100.0 million of the capacity to be used for letters of credit, of which $12.8 million was outstanding at September 30, 2017. 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 September 30, 2017 was $314.7 million.

Senior Unsecured Note Issuance

On August 14, 2017, we issued $550 million in aggregate principal amount of 6.50% senior unsecured notes due October 1, 2025. Interest payments are due April 1 and October 1 of each year with the initial interest payment due April 1, 2018. That issuance generated net proceeds of $540.1 million, net of issuance costs incurred. The net proceeds were used to fund a portion of the purchase price for our acquisition of the Alkali Business.

9. Partners' Capital, Mezzanine Equity and Distributions

At September 30, 2017, our outstanding common units consisted of 122,539,221 Class A units and 39,997 Class B units.

On March 24, 2017, we issued 4,600,000 Class A common units in a public offering at a price of $30.65 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 offering costs, of approximately $140.5 million from that offering.

Distributions

We paid or will pay the following distributions to our common unitholders in 2016 and 2017:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2016			
1st Quarter	May 13, 2016	$0.6725	$73,961
2nd Quarter	August 12, 2016	$0.6900	$81,406
3rd Quarter	November 14, 2016	$0.7000	$82,585
4th Quarter	February 14, 2017	$0.7100	$83,765
2017			
1st Quarter	May 15, 2017	$0.7200	$88,257
2nd Quarter	August 14, 2017	$0.7225	$88,563
3rd Quarter	November 14, 2017 (1)	$0.5000	$61,290

(1) This distribution will be paid to unitholders of record as of October 31, 2017.

Class A Convertible Preferred Units

On September 1, 2017, we sold $750 million of Class A convertible preferred units in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the "Issue Price") to two initial purchasers. Our general partner executed an amendment to our partnership agreement in connection therewith, which, among other things, authorized and established the rights and preferences of our preferred units. Our preferred units are a new class of security that ranks senior to all of our currently outstanding classes or series of limited partner interests with respect to distribution and/or liquidation rights. Holders of our preferred units vote on an as-converted basis with holders of our common units and have certain class voting rights, including with respect to any amendment to the partnership agreement that would adversely affect the rights, preferences or privileges, or otherwise modify the terms, of those preferred units.

Each of our preferred units accumulate quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374), subject to certain adjustments. With respect to any quarter ending on or prior to March 1, 2019, we have the option to pay to the holders of our preferred units the applicable distribution amount in cash, preferred units, or any combination thereof. If we elect to pay all or any portion of a quarterly distribution amount in preferred units, the number of such preferred units will equal the product of (i) the number of then outstanding preferred units and (ii) the quarterly rate. We have elected to pay the distribution amount attributable to the quarter ended on September 30, 2017 in preferred units. For each quarter ending after March 1, 2019, we must pay all distribution amounts in respect of our preferred units in cash.

From time to time after September 1, 2020, we will have the right to cause the conversion of all or a portion of outstanding preferred units into our common units, subject to certain conditions; provided, however, that we will not be permitted to convert more than 7,416,498 of our preferred units in any consecutive twelve-month period. At any time after September 1, 2020, if we have fewer than 592,768 of our preferred units outstanding, we will have the right to convert each outstanding preferred unit into our common units at a conversion rate equal to the greater of (i) the then-applicable conversion rate and (ii) the quotient of (a) the Issue Price and (b) 95% of the volume-weighted average price of our common units for the 30-trading day period ending prior to the date that we notify the holders of our outstanding preferred units of such conversion.

Upon certain events involving certain changes of control in which more than 90% of the consideration payable to the holders of our common units is payable in cash, our preferred units will automatically convert into common units at a conversion ratio equal to the greater of (a) the then applicable conversion rate and (b) the quotient of (i) the product of

(A) the sum of (1) the Issue Price and (2) any accrued and accumulated but unpaid distributions on our preferred units, and (B) a premium factor (ranging from 115% to 101% depending on when such transaction occurs) plus a prorated portion of unpaid partial distributions, and (ii) the volume weighted average price of the common units for the 30 trading days prior to the execution of definitive documentation relating to such change of control.

In connection with other change of control events that do not meet the 90% cash consideration threshold described above, each holder of our preferred units may elect to (a) convert all of its preferred units into our common units at the then applicable conversion rate, (b) if we are not the surviving entity (or if we are the surviving entity, but our common units will cease to be listed), require us to use commercially reasonable efforts to cause the surviving entity in any such transaction to issue a substantially equivalent security (or if we are unable to cause such substantially equivalent securities to be issued, to convert its preferred units into common units in accordance with clause (a) above or exchanged in accordance with clause (d) below or convert at a specified conversion rate), (c) if we are the surviving entity, continue to hold our preferred units or (d) require us to exchange our preferred units for cash or, if we so elect, our common units valued at 95% of the volume-weighted average price of our common units for the 30 consecutive trading days ending on the fifth trading day immediately preceding the closing date of such change of control, at a price per unit equal to the sum of (i) the product of (x) 101% and (y) the Issue Price plus (ii) accrued and accumulated but unpaid distributions and (iii) a prorated portion of unpaid partial distributions.

For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our preferred units may make a one-time election to reset the quarterly distribution amount (a “Rate Reset Election”) to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 10% of the Issue Price. To become effective, the Rate Reset Election requires approval of holders of at least a majority of our then outstanding preferred units and such majority must include each of our initial purchasers (or any affiliate to whom they have transferred their preferred units) if such initial purchaser (including its affiliates) holds at least 25% of the then outstanding preferred units.

Upon the occurrence of a Rate Reset Election, we may redeem our preferred units for cash, in whole or in part (subject to certain minimum value limitations) for an amount per preferred unit equal to such preferred unit’s liquidation value (equal to the Issue Price plus any accrued and accumulated but unpaid distributions, plus a prorated portion of certain unpaid partial distributions in respect of the immediately preceding quarter and the current quarter) multiplied by (i) 110%, prior to September 1, 2024, and (ii) 105% thereafter. Each holder of our preferred units may elect to convert all or any portion of its preferred units into common units initially on a one-for-one basis (subject to customary adjustments and an adjustment for accrued and accumulated but unpaid distributions and limitations) at any time after September 1, 2019 (or earlier upon a change of control, liquidation, dissolution or winding up), provided that any conversion is for at least $50 million or such lesser amount if such conversion relates to all of a holder’s remaining preferred units or has otherwise been approved by us.

If we fail to pay in full any preferred unit distribution amount after March 1, 2019 in respect of any two quarters, whether or not consecutive, then until we pay such distributions in full, we will not be permitted to (a) declare or make any distributions (subject to a limited exceptions for pro rata distributions on our preferred units and parity securities), redemptions or repurchases of any of our limited partner interests that rank junior to or pari passu with our preferred units with respect to rights upon distribution and/or liquidation (including our common units), or (b) issue any such junior or parity securities. If we fail to pay in full any preferred unit distribution after March 1, 2019 in respect of any two quarters, whether or not consecutive, then the preferred unit distribution amount will be reset to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to the then-current annualized distribution rate plus 200 basis points until such default is cured.

In addition to their right to veto a Rate Reset Election under certain circumstances, we have granted each initial purchaser (including its applicable affiliate transferees) certain rights, including (i) the right to appoint an observer, who shall have the right to attend our board meetings for so long as an initial purchaser (including its affiliates) owns at least $200 million of our preferred units; (ii) the right to purchase up to 50% of any parity securities on substantially the same terms offered to other purchasers for so long as an initial purchaser (including its affiliates) owns at least 11,124,747 of our preferred units, and (iii) the right to appoint two directors to our general partner’s board of directors if (and so long as) we fail to pay in full any three quarterly distribution amounts, whether or not consecutive, attributable to any quarter ending after March 1, 2019.

The Rate Reset Election of these preferred units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Unaudited Condensed Consolidated Balance Sheet. See further information in Note 14. The preferred units themselves are classified as mezzanine capital on our Unaudited Condensed Consolidated Balance Sheet.

10. Net Income Per Common Unit

Basic net income per common unit is computed by dividing net income, after considering income attributable to our Series A preferred unitholders, by the weighted average number of common units outstanding.

The dilutive effect of the Series A Convertible Preferred units is calculated using the if-converted method. Under the if-converted method, the Series A Preferred units are assumed to be converted at the beginning of the period (beginning with their respective issuance date), and the resulting common units are included in the denominator of the diluted net income per common unit calculation for the period being presented. Distributions declared in the period and undeclared distributions that accumulated during the period are added back to the numerator for purposes of the if-converted calculation. For the three and nine months ended September 30, 2017, the effect of the assumed conversion of the 22,249,494 Series A convertible preferred units was anti-dilutive and was not included in the computation of diluted earnings per unit.

The following table reconciles net income and weighted average units used in computing basic and diluted net income per common unit (in thousands, except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Income Attributable to Genesis Energy L.P.	$6,312	32,101	$67,135	$91,131
Less: Accumulated distributions attributable to Series A Convertible Preferred Units	(5,469)	—	(5,469)	—
Net Income Available to Common Unitholders	$843	$32,101	$61,666	$91,131
Weighted Average Outstanding Units	122,579	115,718	121,198	111,906
Basic and Diluted Net Income per Common Unit	$0.01	$0.28	$0.51	$0.81

11. Business Segment Information

In the fourth quarter of 2016, we reorganized our operating segments as a result of 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 onshore pipeline transportation segment, formerly reported under its own segment, are now reported in our onshore facilities and transportation segment. The onshore facilities and transportation segment was formerly named our supply and logistics segment. This segment was renamed in the second quarter of 2017 to more accurately describe the nature of its operations. This change is consistent with the increasingly integrated nature of our onshore operations.

On September 1, 2017, we acquired Tronox's Alkali Business for approximately $1.325 billion in cash. We funded that acquisition and the related transaction costs with proceeds from a $750 million private placement of convertible preferred units, a $550 million public offering of notes, our revolving credit facility, and cash on hand. At the closing, we entered into transition service agreements to facilitate the transition of operations and uninterrupted services for both employees and customers. We will report the results of our Alkali Business in our renamed sodium minerals and sulfur services segment, which will include our Alkali Business as well as our existing refinery services operations.

As a result of the above changes, we currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

We currently manage our businesses through four divisions that constitute our reportable segments:

- Offshore pipeline transportation – offshore pipeline transportation and processing of crude oil and natural gas in the Gulf of Mexico;
- Sodium minerals and sulfur services – trona and trona-based exploring, mining, processing, producing, marketing and selling activities, as well as processing high sulfur (or "sour") gas streams as part of refining operations to remove the sulfur and selling the related by-product, NaHS;
- Onshore facilities and transportation – terminalling, blending, storing, marketing and transporting crude oil, petroleum products (primarily fuel oil, asphalt, and other heavy refined products) and CO_2.
- Marine transportation – marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America; and

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 gains and charges, such as depreciation, depletion 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:

	Offshore Pipeline Transportation	Sodium Minerals & Sulfur Services	Marine Transportation	Onshore Facilities & Transportation	Total
Three Months Ended September 30, 2017					
Segment margin (a)	$ 78,228	$30,031	$ 12,649	$ 25,606	$146,514
Capital expenditures (b)	$ 2,356	$1,330,947	$ 23,831	$ 26,578	$1,383,712
Revenues:					
External customers	$ 80,671	$111,756	$ 46,084	$ 247,603	$486,114
Intersegment (c)	—	(1,991)	2,450	(459)	—
Total revenues of reportable segments	$ 80,671	$109,765	$ 48,534	$ 247,144	$486,114
Three Months Ended September 30, 2016					
Segment margin (a)	$ 86,557	$20,526	$ 16,697	$ 17,560	$141,340
Capital expenditures (b)	$ 3,977	$488	$ 26,937	$ 85,348	$116,750
Revenues:					
External customers	$ 89,717	$48,069	$ 53,573	$ 268,691	$460,050
Intersegment (c)	—	(2,344)	1,712	632	—
Total revenues of reportable segments	$ 89,717	$45,725	$ 55,285	$ 269,323	$460,050
Nine Months Ended September 30, 2017					
Segment Margin (a)	$ 243,528	$63,864	$ 39,768	$ 71,999	$419,159
Capital expenditures (b)	$ 8,498	$1,331,892	$ 44,496	$ 115,663	$1,500,549
Revenues:					
External customers	$ 244,653	$204,237	$ 143,599	$ 715,839	$1,308,328
Intersegment (c)	(1,216)	(6,358)	8,439	(865)	—
Total revenues of reportable segments	$ 243,437	$197,879	$ 152,038	$ 714,974	$1,308,328
Nine Months Ended September 30, 2016					
Segment Margin (a)	$ 249,457	$61,586	$ 53,695	$ 63,969	$428,707
Capital expenditures (b)	$ 35,175	$1,645	$ 62,928	$ 258,681	$358,429
Revenues:					
External customers	$ 242,672	$136,437	$ 155,197	$ 750,134	$1,284,440
Intersegment (c)	2,165	(6,852)	4,733	(46)	—
Total revenues of reportable segments	$ 244,837	$129,585	$ 159,930	$ 750,088	$1,284,440

Total assets by reportable segment were as follows:

	September 30, 2017	December 31, 2016
Offshore pipeline transportation	$ 2,507,540	$ 2,575,335
Sodium minerals and sulfur services	1,826,815	395,043
Onshore facilities and transportation	1,939,355	1,875,403
Marine transportation	811,870	813,722
Other assets	52,054	43,089
Total consolidated assets	7,137,634	5,702,592

(a) A reconciliation of total Segment Margin to net income attributable to Genesis Energy, L.P. 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 contributions to equity investees related to same.

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

Reconciliation of total Segment Margin to net income:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Total Segment Margin	$146,514	$141,340	$419,159	$428,707
Corporate general and administrative expenses	(18,230)	(10,420)	(33,694)	(32,269)
Depreciation, depletion, amortization and accretion	(66,436)	(57,103)	(184,213)	(168,491)
Interest expense	(47,388)	(34,735)	(122,117)	(104,657)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income [1]	(7,136)	(9,063)	(25,566)	(30,818)
Non-cash items not included in Segment Margin	(4,788)	993	(6,218)	(3,366)
Cash payments from direct financing leases in excess of earnings	(1,751)	(1,586)	(5,127)	(4,645)
Differences in timing of cash receipts for certain contractual arrangements [2]	5,847	3,624	11,694	9,629
Gain on sale of assets	—	—	26,684	—
Non-cash provision for leased items no longer in use	—	—	(12,589)	—
Income tax expense	(320)	(949)	(878)	(2,959)
Net income attributable to Genesis Energy, L.P.	$6,312	$32,101	$67,135	$91,131

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

(2) Certain cash payments received from customers under certain of our minimum payment obligation contracts are not recognized as revenue under GAAP in the period in which such payments are received.

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 September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Revenues:				
Sales of CO_2 to Sandhill Group, LLC [1]	$750	$878	$2,153	$2,366
Revenues from services and fees to Poseidon Oil Pipeline Company, LLC [2]	3,170	1,979	9,236	5,935
Revenues from product sales to ANSAC	31,774	—	31,774	—
Costs and expenses:				
Amounts paid to our CEO in connection with the use of his aircraft	$165	$165	$495	$495
Charges for services from Poseidon Oil Pipeline Company, LLC (2)	254	251	744	749
Charges for services from ANSAC	454	—	454	—

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

(2) We own 64% interest in Poseidon Oil Pipeline Company, LLC.

Amount due from Related Party

At September 30, 2017 and December 31, 2016 (i) Sandhill Group, LLC owed us $0.2 million and $0.2 million, respectively, for purchases of CO_2, and (ii) Poseidon Oil Pipeline Company, LLC owed us $2.0 million and $1.6 million, respectively, for services rendered.

Transactions with Unconsolidated Affiliates

Poseidon

We are the operator of Poseidon and provide management, administrative and pipeline operator services to Poseidon under an Operation and Management Agreement . Currently, that agreement renews automatically annually unless terminated by either party (as defined in the agreement). Our revenues for the three and nine months ended September 30, 2017 reflect the $2.1 million and $6.3 million, respectively, of fees we earned through the provision of services under that agreement.

ANSAC

We (through a subsidiary of our Alkali Business) are a member of the American Natural Soda Ash Corp. (ANSAC), an organization whose purpose is promoting and increasing the use and sale of natural soda ash and other refined or processed sodium products produced in the U.S. and consumed in specified countries outside of the U.S. Members sell products to ANSAC to satisfy ANSAC's sales commitments to its customers. ANSAC passes its costs through to its members. Those costs include sales and marketing, employees, office supplies, professional, travel, rent, and certain other costs. Those transactions do not necessarily represent arm's length transactions and may not represent all costs we would otherwise incur if we operated the Alkali Business on a stand-alone basis. We also benefit from favorable shipping rates for our direct exports when using ANSAC to arrange for ocean transport. Net sales to ANSAC were $31.8 million during the period September 1, 2017 to September 30, 2017. The costs charged to us by ANSAC, included in operating costs, were $0.5 million during the period September 1, 2017 to September 30, 2017.

Receivables from ANSAC as of September 30, 2017 are as follows:

	September 30, 2017
Receivables:	
ANSAC	$ 59,406
Payables:	
ANSAC	$ 1,317

13. Supplemental Cash Flow Information

The following table provides information regarding the net changes in components of operating assets and liabilities.

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
(Increase) decrease in:		
Accounts receivable	$(79,938)	$11,029
Inventories	31,973	(26,215)
Deferred charges	(293)	(5,291)
Other current assets	(2,769)	5,184
Increase (decrease) in:		
Accounts payable	32,896	(27,213)
Accrued liabilities	(8,131)	(20,901)
Net changes in components of operating assets and liabilities	(26,262)	(63,407)

Payments of interest and commitment fees were $126.9 million and $125.1 million for the nine months ended September 30, 2017 and September 30, 2016, respectively. We capitalized interest of $13.8 million and $19.9 million during the nine months ended September 30, 2017 and September 30, 2016.

At September 30, 2017 and September 30, 2016, we had incurred liabilities for fixed and intangible asset additions totaling $25.7 million and $55.3 million, respectively, that had not been paid at the end of the quarter, and, therefore, were not

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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.

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 Unaudited Consolidated 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 Unaudited Consolidated Balance Sheets.

At September 30, 2017, we had the following outstanding derivative commodity contracts that were entered into to economically hedge inventory or fixed price purchase commitments.

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	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	694	—
Weighted average contract price per bbl	$ 48.03	$ —
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	482	322
Weighted average contract price per bbl	$ 50.17	$ 50.76
Diesel futures:		
Contract volumes (1,000 bbls)	11	11
Weighted average contract price per bbl	$ 1.71	$ 1.76
NYM RBOB Gas futures:		
Contract volumes (42,000 gallons)	—	4
Weighted average contract price per gallon	$ —	$ 1.59
Fuel oil futures:		
Contract volumes (1,000 bbls)	175	70
Weighted average contract price per bbl	$ 48.10	$ 48.51
Crude oil options:		
Contract volumes (1,000 bbls)	50	20
Weighted average premium received	$ 0.63	$ 0.19

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 September 30, 2017 and December 31, 2016:

Fair Value of Derivative Assets and Liabilities

	Unaudited Condensed Consolidated Balance Sheets Location	Fair Value September 30, 2017	Fair Value December 31, 2016
Asset Derivatives:			
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$503	$ 443
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(503)	(443)
Net amount of assets presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$—	$ —
Commodity derivatives - futures and call options (designated hedges):			
Gross amount of recognized assets	Current Assets - Other	$43	$ 3,321
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(43)	(3,321)
Net amount of assets presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$—	$ —
Liability Derivatives:			
Preferred Distribution Rate Reset Election (2)	Other long-term liabilities	(36,726)	—
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(1,167)	$ (1,772)
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other (1)	1,167	1,772
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$—	$ —
Commodity derivatives - futures and call options (designated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(2,643)	$ (9,506)
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other (1)	2,459	7,589
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$(184)	$ (1,917)

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

(2) Refer to Note 9 and Note 15 for additional discussion surrounding the Preferred Distribution Rate Reset Election derivative.

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 September 30, 2017, we had a net broker receivable of approximately $3.1 million (consisting of initial margin of $2.4 million increased by $0.7 million of variation margin). As of December 31, 2016, we had a net broker receivable of approximately $5.6 million (consisting of initial margin of $5.1 million increased by $0.5 million of variation margin). At

September 30, 2017 and December 31, 2016, 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.

Preferred Distribution Rate Reset Election

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our preferred units may make a Rate Reset Election to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 10% of the Issue Price. The Rate Reset Election of the preferred units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Unaudited Condensed Consolidated Balance Sheet. Corresponding changes in fair value are recognized in Other Expense in our Unaudited Condensed Consolidated Statement of Operations. At September 30, 2017, the fair value of this embedded derivative was a liability of $36.7 million. See Note 9 for additional information regarding our Series A preferred units and the Rate Reset Election.

Effect on Operating Results

	Unaudited Condensed Consolidated Statements of Operations Location	Amount of Gain (Loss) Recognized in Income			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2017	2016	2017	2016
Commodity derivatives - futures and call options:					
Contracts designated as hedges under accounting guidance	Onshore facilities and transportation product costs	$(3,399)	$1,672	$8,433	$(8,279)
Contracts not considered hedges under accounting guidance	Onshore facilities and transportation product costs	(1,329)	(262)	650	(3,744)
Total commodity derivatives		$(4,728)	$1,410	$9,083	$(12,023)
Preferred Distribution Rate Reset Election	Other expense	$(2,276)	$—	$(2,276)	$—

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.

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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 September 30, 2017 and December 31, 2016.

	Fair Value at September 30, 2017			Fair Value at December 31, 2016		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$546	$ —	$—	$3,764	$ —	$ —
Liabilities	$(3,810)	$ —		$(11,278)	$ —	$ —
Preferred Distribution Rate Reset Election	$—	$ —	$(36,726)	$—	$ —	$ —

Rollforward of Level 3 Fair Value Measurements

The following table provides a reconciliation of changes in fair value at the beginning and ending balances for our derivatives classified as level 3:

	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
Beginning Balance	—	—
Initial valuation of Preferred Distribution Rate Reset Election	(34,450)	(34,450)
Net Loss for the period included in earnings	(2,276)	(2,276)
Ending Balance	(36,726)	(36,726)

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.

The fair value of embedded derivative feature is based on a valuation model that estimates the fair value of the convertible preferred units with and without a Rate Reset Election. This model contains inputs, including our common unit price, a ten year history of the dividend yield, default probabilities and timing estimates which involve management judgment. A significant increase or decrease in the value of these inputs could result in a material change in fair value to this embedded derivative feature. We report unrealized gains and losses associated with this embedded derivative in our Unaudited Condensed Consolidated Statements of Operations as Other income (expense), net.

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 September 30, 2017 our senior unsecured notes had a carrying value and fair value of $2.4 billion compared to $1.8 billion and $1.9 billion, respectively, at December 31, 2016. 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. Commitments and Contingencies

We are subject to various environmental laws and regulations. Policies and procedures are in place to aid in monitoring compliance and detecting and addressing releases of crude oil from our pipelines or other facilities and from our mining operations relating to our Alkali Business; 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.

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In the second quarter of 2017, we recorded a non-cash provision of $12.6 million (included within Onshore facilities and transportation operating costs in our Unaudited Condensed Consolidated Statements of Operations) relating to certain leased railcars no longer in use. Of this amount, $4.1 million is considered current and included in accrued liabilities in our Unaudited Condensed Consolidated Balance Sheet, with the remainder included in other long-term liabilities.

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17. Condensed Consolidating Financial Information

Our $2.4 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 8 for additional information regarding our consolidated debt obligations.

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

Unaudited Condensed Consolidating Balance Sheet
September 30, 2017

	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	$ —	$8,960	$ 728	$—	$9,694
Other current assets	75	—	569,457	11,836	(238)	581,130
Total current assets	81	—	578,417	12,564	(238)	590,824
Fixed assets, at cost	—	—	5,444,707	77,585	—	5,522,292
Less: Accumulated depreciation	—	—	(655,808)	(26,092)	—	(681,900)
Net fixed assets	—	—	4,788,899	51,493	—	4,840,392
Mineral Leaseholds	—	—	622,756	—	—	622,756
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	15,229	—	382,916	128,306	(151,026)	375,425
Advances to affiliates	3,889,517	—	—	82,479	(3,971,996)	—
Equity investees	—	—	383,191	—	—	383,191
Investments in subsidiaries	2,666,281	—	81,135	—	(2,747,416)	—
Total assets	$6,571,108	$ —	$7,162,360	$ 274,842	$(6,870,676)	$7,137,634
LIABILITIES AND CAPITAL						
Current liabilities	$34,731	$ —	$321,339	$ 8,092	$(151)	$364,011
Senior secured credit facility	1,372,500	—	—	—	—	1,372,500
Senior unsecured notes	2,358,049	—	—	—	—	2,358,049
Deferred tax liabilities	—	—	26,399	—	—	26,399
Advances from affiliates	—	—	3,971,992	—	(3,971,992)	—
Other liabilities	36,727	—	183,552	187,057	(150,874)	256,462
Total liabilities	3,802,007	—	4,503,282	195,149	(4,123,017)	4,377,421
Mezzanine Capital:						
Series A Convertible Preferred Units	691,708	—	—	—	—	691,708
Partners' capital, common units	2,077,393	—	2,659,078	88,581	(2,747,659)	2,077,393
Noncontrolling interests	—	—	—	(8,888)	—	(8,888)
Total liabilities, mezzanine capital and partners' capital	$6,571,108	$ —	$7,162,360	$ 274,842	$(6,870,676)	$7,137,634

GENESIS ENERGY, L.P.
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Unaudited Condensed Consolidating Balance Sheet
December 31, 2016

	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	$ —	$6,360	$ 663	$—	$7,029
Other current assets	50	—	340,555	12,237	(302)	352,540
Total current assets	56	—	346,915	12,900	(302)	359,569
Fixed assets, at cost	—	—	4,685,811	77,585	—	4,763,396
Less: Accumulated depreciation	—	—	(524,315)	(24,217)	—	(548,532)
Net fixed assets	—	—	4,161,496	53,368	—	4,214,864
Mineral Leaseholds	—	—	—	—	—	—
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	10,696	—	390,214	133,980	(140,533)	394,357
Advances to affiliates	2,650,930	—	—	73,295	(2,724,225)	—
Equity investees	—	—	408,756	—	—	408,756
Investments in subsidiaries	2,594,882	—	80,735	—	(2,675,617)	—
Total assets	$5,256,564	$ —	$5,713,162	$ 273,543	$(5,540,677)	$5,702,592
LIABILITIES AND CAPITAL						
Current liabilities	$34,864	$ —	$211,591	$ 14,505	$(157)	$260,803
Senior secured credit facility	1,278,200	—	—	—	—	1,278,200
Senior unsecured notes	1,813,169	—	—	—	—	1,813,169
Deferred tax liabilities	—	—	25,889	—	—	25,889
Advances from affiliates	—	—	2,724,224	—	(2,724,224)	—
Other liabilities	—	—	165,266	179,592	(140,377)	204,481
Total liabilities	3,126,233	—	3,126,970	194,097	(2,864,758)	3,582,542
Mezzanine Capital:						
Series A Convertible Preferred Units	—	—	—	—	—	—
Partners' capital, common units	2,130,331	—	2,586,192	89,727	(2,675,919)	2,130,331
Noncontrolling interests	—	—	—	(10,281)	—	(10,281)
Total liabilities, mezzanine capital and partners' capital	$5,256,564	$ —	$5,713,162	$ 273,543	$(5,540,677)	$5,702,592

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Unaudited Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2017

	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:						
Offshore pipeline transportation services	$ —	$ —	$ 80,671	$ —	$ —	$ 80,671
Sodium minerals and sulfur services	—	—	109,292	2,069	(1,596)	109,765
Marine transportation	—	—	48,534	—	—	48,534
Onshore facilities and transportation	—	—	242,547	4,597	—	247,144
Total revenues	—	—	481,044	6,666	(1,596)	486,114
COSTS AND EXPENSES:						
Onshore facilities and transportation	—	—	225,716	313	—	226,029
Marine transportation costs	—	—	35,789	—	—	35,789
Sodium minerals and sulfur services operating costs	—	—	78,869	2,092	(1,596)	79,365
Offshore pipeline transportation operating costs	—	—	17,928	762	—	18,690
General and administrative	—	—	19,409	—	—	19,409
Depreciation and amortization	—	—	63,107	625	—	63,732
Gain on sale of assets	—	—	—	—	—	—
Total costs and expenses	—	—	440,818	3,792	(1,596)	443,014
OPERATING INCOME	—	—	40,226	2,874	—	43,100
Equity in earnings of subsidiaries	55,971	—	(388)	—	(55,583)	—
Equity in earnings of equity investees	—	—	13,044	—	—	13,044
Interest (expense) income, net	(47,383)	—	3,450	(3,455)	—	(47,388)
Other expense	(2,276)	—	—	—	—	(2,276)
Income before income taxes	6,312	—	56,332	(581)	(55,583)	6,480
Income tax benefit (expense)	—	—	(322)	2	—	(320)
NET INCOME	6,312	—	56,010	(579)	(55,583)	6,160
Net loss attributable to noncontrolling interest	—	—	—	152	—	152
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 6,312	$ —	$ 56,010	$ (427)	$ (55,583)	$ 6,312
Less: Accumulated distributions attributable to Series A Convertible Preferred Units	(5,469)	—	—	—	—	(5,469)
NET INCOME AVAILABLE TO COMMON UNIT HOLDERS	$ 843	$ —	$ 56,010	$ (427)	$ (55,583)	$ 843

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Unaudited Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2016

	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:						
Offshore pipeline transportation services	$ —	$ —	$ 89,717		$ —	$ 89,717
Sodium minerals and sulfur services	—	—	45,262	2,981	(2,518)	45,725
Marine transportation	—	—	55,285	—	—	55,285
Onshore facilities and transportation	—	—	264,326	4,997	—	269,323
Total revenues	—	—	454,590	7,978	(2,518)	460,050
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	252,450	255	—	252,705
Marine transportation costs	—	—	38,490	—	—	38,490
Sodium minerals and sulfur services operating costs	—	—	24,577	3,018	(2,518)	25,077
Offshore pipeline transportation operating costs	—	—	22,533	589	—	23,122
General and administrative	—	—	11,212	—	—	11,212
Depreciation and amortization	—	—	53,640	625	—	54,265
Total costs and expenses	—	—	402,902	4,487	(2,518)	404,871
OPERATING INCOME	—	—	51,688	3,491	—	55,179
Equity in earnings of subsidiaries	66,811	—	28	—	(66,839)	—
Equity in earnings of equity investees	—	—	12,488	—	—	12,488
Interest (expense) income, net	(34,710)	—	3,595	(3,620)	—	(34,735)
Other expense	—	—	—	—	—	—
Income before income taxes	32,101	—	67,799	(129)	(66,839)	32,932
Income tax expense	—	—	(949)	—	—	(949)
NET INCOME	32,101	—	66,850	(129)	(66,839)	31,983
Net loss attributable to noncontrolling interest	—	—	—	118	—	118
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 32,101	$ —	$ 66,850	$ (11)	$ (66,839)	$ 32,101
Less: Accumulated distributions attributable to Series A Convertible Preferred Units	—	—	—	—	—	—
NET INCOME AVAILABLE TO COMMON UNIT HOLDERS	$ 32,101	$ —	$ 66,850	$ (11)	$ (66,839)	$ 32,101

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Unaudited Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2017

	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:						
Offshore pipeline transportation services	$ —	$ —	$ 243,437	$ —	$ —	$ 243,437
Sodium minerals and sulfur services	—	—	197,321	5,968	(5,410)	197,879
Marine transportation	—	—	152,038	—	—	152,038
Onshore facilities and transportation	—	—	700,908	14,066	—	714,974
Total revenues	—	—	1,293,704	20,034	(5,410)	1,308,328
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	661,842	853	—	662,695
Marine transportation costs	—	—	111,980	—	—	111,980
Sodium minerals and sulfur services operating costs	—	—	132,608	6,137	(5,410)	133,335
Offshore pipeline transportation operating costs	—	—	52,396	2,286	—	54,682
General and administrative	—	—	38,723	—	—	38,723
Depreciation and amortization	—	—	174,578	1,875	—	176,453
Gain on sale of assets	—	—	(26,684)	—	—	(26,684)
Total costs and expenses	—	—	1,145,443	11,151	(5,410)	1,151,184
OPERATING INCOME	—	—	148,261	8,883	—	157,144
Equity in earnings of subsidiaries	191,471	—	(1,033)	—	(190,438)	—
Equity in earnings of equity investees	—	—	34,805	—	—	34,805
Interest (expense) income, net	(122,060)	—	10,436	(10,493)	—	(122,117)
Other expense	(2,276)	—	—	—	—	(2,276)
Income before income taxes	67,135	—	192,469	(1,610)	(190,438)	67,556
Income tax expense	—	—	(880)	2	—	(878)
NET INCOME	67,135	—	191,589	(1,608)	(190,438)	66,678
Net loss attributable to noncontrolling interest	—	—	—	457	—	457
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 67,135	$ —	$ 191,589	$ (1,151)	$ (190,438)	$ 67,135
Less: Accumulated distributions attributable to Series A Convertible Preferred Units	(5,469)	—	—	—	—	$ (5,469)
NET INCOME AVAILABLE TO COMMON UNIT HOLDERS	$ 61,666	$ —	$ 191,589	$ (1,151)	$ (190,438)	$ 61,666

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Nine Months Ended September 30, 2016

	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:						
Offshore pipeline transportation services	$ —	$ —	$ 244,837		$ —	$ 244,837
Sodium minerals and sulfur services	—	—	129,671	5,499	(5,585)	129,585
Marine transportation	—	—	159,930	—	—	159,930
Onshore facilities and transportation	—	—	734,560	15,528	—	750,088
Total revenues	—	—	1,268,998	21,027	(5,585)	1,284,440
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	691,763	831	—	692,594
Marine transportation costs	—	—	105,942	—	—	105,942
Sodium minerals and sulfur services operating costs	—	—	67,190	6,036	(5,585)	67,641
Offshore pipeline transportation operating costs	—	—	61,882	1,850	—	63,732
General and administrative	—	—	34,716	—	—	34,716
Depreciation and amortization	—	—	154,925	1,875	—	156,800
Total costs and expenses	—	—	1,116,418	10,592	(5,585)	1,121,425
OPERATING INCOME	—	—	152,580	10,435	—	163,015
Equity in earnings of subsidiaries	195,674	—	(50)	—	(195,624)	—
Equity in earnings of equity investees	—	—	35,362	—	—	35,362
Interest (expense) income, net	(104,543)	—	10,861	(10,975)	—	(104,657)
Other expense	—	—	—	—	—	—
Income before income taxes	91,131	—	198,753	(540)	(195,624)	93,720
Income tax (expense) benefit	—	—	(2,956)	(3)	—	(2,959)
NET INCOME	91,131	—	195,797	(543)	(195,624)	90,761
Net loss attributable to noncontrolling interest	—	—	—	370	—	370
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 91,131	$ —	$ 195,797	$ (173)	$ (195,624)	$ 91,131
Less: Accumulated distributions attributable to Series A Convertible Preferred Units	—	—	—	—	—	$ —
NET INCOME AVAILABLE TO COMMON UNIT HOLDERS	$ 91,131	$ —	$ 195,797	$ (173)	$ (195,624)	$ 91,131

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

Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2017

	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 provided by operating activities	$ 142,721	$ —	$ 333,709	$ (8,346)	$ (250,294)	$ 217,790
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(182,653)	—	—	(182,653)
Cash distributions received from equity investees - return of investment	—	—	14,517	—	—	14,517
Investments in equity investees	(140,513)	—	—	—	140,513	—
Acquisitions	—	—	(1,325,759)	—	—	(1,325,759)
Intercompany transfers	(1,238,585)	—	—	—	1,238,585	—
Repayments on loan to non-guarantor subsidiary	—	—	(159)	—	159	—
Contributions in aid of construction costs	—	—	124	—	—	124
Proceeds from asset sales	—	—	39,204	—	—	39,204
Other, net	—	—	—	—	—	—
Net cash used in investing activities	(1,379,098)	—	(1,454,726)	—	1,379,257	(1,454,567)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,247,700	—	—	—	—	1,247,700
Repayments on senior secured credit facility	(1,153,400)	—	—	—	—	(1,153,400)
Proceeds from issuance of senior unsecured notes	550,000	—	—	—	—	550,000
Proceeds from issuance of Series A convertible preferred units, net	729,958	—	—	—	—	729,958
Debt issuance costs	(17,808)	—	—	—	—	(17,808)
Intercompany transfers	—	—	1,242,475	(3,890)	(1,238,585)	—
Issuance of common units for cash, net	140,513	—	140,513	—	(140,513)	140,513
Distributions to common unitholders	(260,586)	—	(260,586)	—	260,586	(260,586)
Contributions from noncontrolling interest	—	—	—	1,850	—	1,850
Other, net	—	—	1,215	10,451	(10,451)	1,215
Net cash used in financing activities	1,236,377	—	1,123,617	8,411	(1,128,963)	1,239,442
Net increase in cash and cash equivalents	—	—	2,600	65	—	2,665
Cash and cash equivalents at beginning of period	6	—	6,360	663	—	7,029
	$ 6	$ —	$ 8,960	$ 728	$ —	$ 9,694

Cash and cash equivalents at end of period

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

Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2016

	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 provided by operating activities	$ 122,884	$ —	$ 310,723	$ 6,781	$ (211,991)	$ 228,397
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(363,218)	—	—	(363,218)
Cash distributions received from equity investees - return of investment	—	—	16,652	—	—	16,652
Investments in equity investees	(298,051)	—	—	—	298,051	—
Acquisitions	—	—	(25,394)	—	—	(25,394)
Intercompany transfers	54,148	—	—	—	(54,148)	—
Repayments on loan to non-guarantor subsidiary	—	—	4,526	—	(4,526)	—
Contributions in aid of construction costs	—	—	12,208	—	—	12,208
Proceeds from asset sales	—	—	3,303	—	—	3,303
Other, net	—	—	185	—	—	185
Net cash used in investing activities	(243,903)	—	(351,738)	—	239,377	(356,264)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	883,600	—	—	—	—	883,600
Repayments on senior secured credit facility	(831,600)	—	—	—	—	(831,600)
Debt issuance costs	(1,578)	—	—	—	—	(1,578)
Intercompany transfers	—	—	(35,144)	(19,004)	54,148	—
Issuance of common units for cash, net	298,051	—	298,051	—	(298,051)	298,051
Distributions to common unitholders	(227,454)	—	(227,454)	—	227,454	(227,454)
Other, net	—	—	(600)	10,937	(10,937)	(600)
Net cash provided by financing activities	121,019	—	34,853	(8,067)	(27,386)	120,419
Net decrease in cash and cash equivalents	—	—	(6,162)	(1,286)	—	(7,448)
Cash and cash equivalents at beginning of period	6	—	8,288	2,601	—	10,895
Cash and cash equivalents at end of period	$ 6	$ —	$ 2,126	$ 1,315	$ —	$ 3,447

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, 2016.

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

- Overview
- Results of Operations
- Liquidity and Capital Resources
- Non-GAAP Financial Measures
- Commitments and Off-Balance Sheet Arrangements
- Forward Looking Statements

Overview

On September 1, 2017, we completed the $1.325 billion accretive acquisition of Tronox Limited's ("Tronox's") trona and trona-based exploring, mining, processing, producing, marketing and selling business (the "Alkali Business"). Our Alkali Business is the largest producer in the world of natural soda ash. We funded that acquisition and the related transaction costs with proceeds from a $750 million private placement of convertible preferred units, a $550 million public offering of notes, our revolving credit facility, and cash on hand. At the closing, we entered into a transition service agreement to facilitate the transition of operations and uninterrupted services for both employees and customers.

We recently made the strategic decision to re-set our quarterly distribution and provided a plan for visible, achievable long term distribution growth and a clear path forward to deleveraging. These steps, along with the future stable and repeatable cash flows from our recently completed acquisition of the Alkali Business as well as the anticipated ramp from our recent strategic investments, we believe further enhance our financial flexibility to opportunistically pursue accretive organic projects and acquisitions should they present themselves. In this context, however, we would reiterate, we currently have no plans to access the equity capital markets in the immediate future, including under our "at the market" equity program, which in fact has never been used. Overall, we believe these actions to strengthen our balance sheet and enhance our financial flexibility are the best actions we can take to allow us to generate strong total returns for our unitholders in the years ahead.

Our quarterly results were negatively impacted by a number of events, such as Hurricane Harvey (a 1,000-year hurricane), the planned regulatory dry-docking of our M/T American Phoenix as required every five years, some extended turnarounds at several offshore hubs, and turnarounds at several facilities in Alberta. Notwithstanding these negatives, our legacy businesses are performing as expected, and we are seeing increased contributions from our recently completed organic projects in the Baton Rouge corridor, in and around Texas City and in Wyoming. Additionally, the quarter reflects only one month of contribution from our recently acquired soda ash operations, which performance is exceeding our expectations.

Earlier this year, we announced and discussed our intent to market certain non-strategic assets with targeted proceeds of $50-$75 million. While not yet fully recognized in our reported results, we have to date consummated sales for total cash proceeds of approximately $76 million, representing in the aggregate a GAAP gain of approximately $40 million and at an implied multiple to us of in excess of 30 times, none of which directly flows through our non-GAAP measures of EBITDA or Available Cash. We continue to evaluate other non-strategic assets in our portfolio, although there can be no assurances of additional transactions.

We reported net income attributable to Genesis Energy, L.P. of $6.3 million, or $0.01 per common unit, during the three months ended September 30, 2017 ("2017 Quarter") compared to net income attributable to Genesis Energy, L.P. of $32.1 million, or $0.28 per common unit, during the three months ended September 30, 2016 ("2016 Quarter"). Net income was negatively affected by approximately $25.2 million, or $0.21 per unit, due to transaction and financing expenses, as well as an increase in interest expense, primarily driven by our acquisition of the Alkali Business during the quarter. For the 2017 Quarter, our operating results include one month of activity related to the Alkali Business for the month of September.

Cash flow from operating activities was $33.8 million for the 2017 Quarter compared to $124.7 million for the 2016 Quarter. Cash flows from operating activities for the 2017 Quarter were also negatively affected by certain non-recurring costs

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described above as well as an increase in net working capital that is not necessarily meaningful to the underlying performance of the our businesses.

Available Cash before Reserves (as defined below in "Non-GAAP Financial Measures") was $91.8 million for the 2017 Quarter, a decrease of $3.2 million, or 3.4%, from the 2016 Quarter. See “Non-GAAP Financial Measures” below for additional information on Available Cash before Reserves and Segment Margin.

Segment Margin (as defined below in "Non-GAAP Financial Measures") was $146.5 million for the 2017 Quarter, an increase of $5.2 million, or 3.7%, from the 2016 Quarter.

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

Distribution

In October 2017, we declared our quarterly distribution to our common unitholders $0.50 per units related to the 2017 Quarter, which will be paid in November 2017.

With respect to our Class A Convertible Preferred Units, we have declared a payment-in-kind ("PIK") of the quarterly distribution, which will result in the issuance of an additional 162,234 Class A Convertible Preferred Units. This PIK amount, as pro-rated based on the period these units were outstanding, equates to a distribution of $0.2458 per Class A Convertible Preferred Unit for the 2017 Quarter, or $2.9496 annualized. These distributions will be payable on November 14, 2017 to unitholders holders of record at the close of business on November 3, 2017.

Segment Reporting Change

Beginning in the fourth quarter of 2016, we started reporting our results on a comparative basis in four business segments. Due to the increasingly integrated nature of our onshore operations, the results of our onshore pipeline transportation segment, formerly reported under its own segment, is now reported in our onshore facilities and transportation segment. The onshore facilities and transportation segment also now includes what was formerly reported in our supply and logistics segment. This segment was renamed in the second quarter of 2017 to more accurately describe the nature of its operations. We will report the results of the Alkali Business in our renamed sodium minerals and sulfur services segment, which will include the Alkali Business as well as our existing refinery services operations.

As a result of the above changes, we currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation, and marine transportation. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

Results of Operations

Revenues and Costs and Expenses

Our revenues for the 2017 Quarter increased $26.1 million, or 5.7%, from the 2016 Quarter, which includes the effects of one month of revenue contributed by the Alkali Business. Additionally, our costs and expenses (excluding interest) increased $38.1 million, or 9.4%, between those two periods. This includes approximately $10.2 million of third party financing, legal and accounting costs primarily attributable to the acquisition of the Alkali Business in the 2017 Quarter. Excluding these items, costs and expenses would have increased $27.9 million between the two periods.

A substantial portion of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products through our onshore facilities and transportation segment. The decrease in our revenues and costs in this segment between those two quarterly periods is primarily attributable to decreases in crude oil and petroleum product sales volumes as discussed further below. In general, we do not expect fluctuations in prices for crude oil and natural gas to materially affect our net income, Available Cash before Reserves or Segment Margin to the same extent they affect our revenues and costs. We have limited our direct commodity price exposure related to crude oil and petroleum products through the broad use of fee-based service contracts, back-to-back purchase and sale arrangements, and hedges. As a result, changes in the price of crude oil would proportionately impact both our revenues and our costs, with a disproportionately smaller net impact on our Segment Margin.

As discussed throughout this document and throughout our Annual Report on Form 10-K, we have some indirect exposure to certain changes in prices for crude oil and petroleum products, particularly if they are significant and extended. We tend to experience more demand for certain of our services when prices increase significantly over extended periods of time, and we tend to experience less demand for certain of our services when prices decrease significantly over extended periods of time.

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For additional information regarding certain of our indirect exposure to commodity prices, see our segment-by-segment analysis below and the section of our Annual Report entitled “Risks Related to Our Business”.
Prices of crude oil have slightly recovered since the 2016 Quarter. The average closing prices for West Texas Intermediate crude oil on the New York Mercantile Exchange ("NYMEX") increased 7.3% to $48.21 per barrel in the 2017 Quarter, as compared to $44.94 per barrel in the 2016 Quarter. We would expect changes in crude oil prices to continue to proportionately affect our revenues and costs attributable to our purchase and sale of crude oil and petroleum products, producing minimal direct impact on Segment Margin from those operations. However, due to the indirect exposure to changes in prices discussed above, the factors addressed in our onshore facilities and transportation segment discussion below, and the fact the crude oil prices have remained low for an extended period of time as compared to the five year period before 2015, our crude oil and petroleum product sales volumes have continued to decline, including a 19.0% decrease in the 2017 Quarter as compared to the 2016 Quarter.
Within our legacy business we have two distinct, complementary types of operations-(i) our onshore-based refinery-centric crude oil and refined petroleum products transportation, facilities, logistics, and handling operations, focusing predominantly on refinery-centric customers (as opposed to producers), and (ii) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, focusing on integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large reservoir, long-lived crude oil and natural gas properties. Refiners are the shippers of over 80% of the volumes transported on our onshore crude pipelines, and refiners contract for over 85% of the use of our inland barges, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes. The shippers on our offshore 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. Given these facts, we do not expect changes in commodity prices to impact our net income, Available Cash before Reserves or Segment Margin in the same manner in which they impact our revenues and costs derived from the purchase and sale of crude oil and petroleum products.
A portion of our revenues and costs are derived from the sale of natural soda ash, which has significant cost advantages over any synthetic production methods. We believe the significant cost advantage in the production of natural soda ash compared to synthetically produced soda ash will remain for the foreseeable future. Natural soda ash accounts for approximately 25% of the world's production and therefore given these facts, we believe we are able to somewhat mitigate the effects of market specific factors on Net Income, Available Cash before Reserves and Segment Margin in the soda ash market in which we operate. Additionally, changes in certain of our operating costs between the respective quarters, such as those associated with our sodium minerals and sulfur services, offshore pipeline and marine transportation segments, are not correlated with crude oil prices. We discuss certain of those costs in further detail below in our segment-by-segment analysis.

Segment Margin

The contribution of each of our segments to total Segment Margin in the three and nine months ended September 30, 2017 and September 30, 2016 was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Offshore pipeline transportation	78,228	86,557	$243,528	$249,457
Sodium minerals and sulfur services	30,031	20,526	63,864	61,586
Onshore facilities and transportation	25,606	17,560	71,999	63,969
Marine transportation	12,649	16,697	39,768	53,695
Total Segment Margin	$146,514	$141,340	$419,159	$428,707

We define Segment Margin as revenues less product costs, operating expenses, and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees and certain litigation expenses that are not deducted to determine our Pro Forma Adjusted EBITDA under our revolving credit facility. Our Segment Margin definition also includes the non-income portion of payments received under direct financing leases and eliminates non-cash revenues, expenses, gains, losses and charges (such as depreciation and amortization, unrealized gain or loss on derivative transactions not designated as hedges for accounting purposes, gain or loss on sale of non-surplus assets and equity based compensation expense that is not settled in cash). Our reconciliation of total Segment Margin to net income reflects that Segment Margin (as defined

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above) excludes corporate general and administrative expenses, non-cash gains and charges, depreciation, amortization and accretion, interest expense, certain non-cash items, and unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. See "Non-GAAP Financial Measures" for further discussion surrounding total Segment Margin.

A reconciliation of total Segment Margin to net income for the periods presented is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Total Segment Margin	$146,514	$141,340	$419,159	$428,707
Corporate general and administrative expenses	(18,230)	(10,420)	(33,694)	(32,269)
Depreciation, depletion, amortization and accretion	(66,436)	(57,103)	(184,213)	(168,491)
Interest expense	(47,388)	(34,735)	(122,117)	(104,657)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income (1)	(7,136)	(9,063)	(25,566)	(30,818)
Non-cash items not included in Segment Margin	(4,788)	993	(6,218)	(3,366)
Cash payments from direct financing leases in excess of earnings	(1,751)	(1,586)	(5,127)	(4,645)
Gain on sale of assets	—	—	26,684	—
Non-cash provision for leased items no longer in use	—	—	(12,589)	—
Differences in timing of cash receipts for certain contractual arrangements (2)	5,847	3,624	11,694	9,629
Income tax expense	(320)	(949)	(878)	(2,959)
Net income attributable to Genesis Energy, L.P.	$6,312	$32,101	$67,135	$91,131

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

(2) Certain cash payments received from customers under certain of our minimum payment obligation contracts are not recognized as revenue under GAAP in the period in which such payments are received.

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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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Offshore crude oil pipeline revenue	$67,506	$69,759	$204,585	$199,391
Offshore natural gas pipeline revenue	13,164	19,957	38,852	45,445
Offshore pipeline operating costs, excluding non-cash expenses	(15,979)	(20,292)	(46,859)	(54,463)
Distributions from equity investments [1]	19,535	20,880	59,100	64,502
Other	(5,998)	(3,747)	(12,150)	(5,418)
Offshore pipeline transportation Segment Margin	$78,228	$86,557	$243,528	$249,457
Volumetric Data 100% basis:				
Crude oil pipelines (average barrels/day unless otherwise noted):				
CHOPS	203,697	190,613	220,374	200,753
Poseidon	257,093	263,519	258,031	259,446
Odyssey	135,787	107,252	122,433	106,622
GOPL [2]	8,317	6,287	8,166	5,839
Total crude oil offshore pipelines	604,894	567,671	609,004	572,660
Natural gas transportation volumes (MMBtus/d)	467,095	775,546	516,974	656,452
Volumetric Data net to our ownership interest [3]:				
Crude oil pipelines (average barrels/day unless otherwise noted):				
CHOPS	203,697	190,613	220,374	200,753
Poseidon	164,540	168,652	165,140	166,045
Odyssey	39,378	31,103	35,506	30,920
GOPL [2]	8,317	6,287	8,166	5,839
Total crude oil offshore pipelines	415,932	396,655	429,186	403,557
Natural gas transportation volumes (MMBtus/d)	189,778	502,792	237,328	374,950

(1) Offshore pipeline transportation Segment Margin includes distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2017 and 2016, respectively.

(2) One of our wholly-owned subsidiaries (GEL Offshore Pipeline, LLC, or "GOPL") owns our undivided interest in the Eugene Island pipeline system.

(3) Volumes are the product of our effective ownership interest through the year, including changes in ownership interest, multiplied by the relevant throughput over the given year.

Three Months Ended September 30, 2017 Compared with Three Months Ended September 30, 2016

Offshore Pipeline Transportation Segment Margin for the 2017 Quarter decreased $8.3 million, or 10%, from the 2016 Quarter. The 2017 Quarter was negatively impacted by both anticipated and unanticipated downtime at several major fields, including weather related downtime, affecting certain of our deepwater Gulf of Mexico customers and thus certain of our key crude oil and natural gas assets, including our Poseidon pipeline and certain associated laterals which we own. While such downtime was temporary, we expect additional downtime relating to weather and maintenance involving certain customers' fields during the fourth quarter of 2017. The quarter also reflects the effects of a contractual step down to a lower transportation rate for a certain lateral which we own that will be in place going forward. In addition, the 2016 Quarter benefited from the temporary diversion of certain natural gas volumes from third party gas pipelines to one of our gas pipelines and related facilities due to disruptions at onshore processing facilities where such volumes typically flow.

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Nine Months Ended September 30, 2017 Compared with Nine Months Ended September 30, 2016

Offshore pipeline transportation Segment Margin for the first nine months of 2017 decreased $5.9 million, or 2%, from the first nine months of 2016. The first nine months of 2017 was negatively impacted by both anticipated and unanticipated downtime at several major fields, including weather related downtime, affecting certain of our deepwater Gulf of Mexico customers and thus certain of our key crude oil and natural gas assets, including our Poseidon pipeline and certain associated laterals which we own. While such downtime was temporary, we expect additional downtime relating to weather and maintenance involving certain customers' fields during the fourth quarter of 2017. The nine months ended September 30, 2017 also reflects the effects of a contractual step down to a lower transportation rate for a certain lateral which we own that will be in place going forward. In addition, the nine months ended September 30, 2016 benefited from the temporary diversion of certain natural gas volumes from third party gas pipelines to one of our gas pipelines and related facilities due to disruptions at onshore processing facilities where such volumes typically flow.

Sodium Minerals and Sulfur Services Segment

Operating results for our sodium minerals and sulfur services segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Volumes sold:				
NaHS volumes (Dry short tons "DST")	30,381	34,299	95,575	96,116
Soda Ash volumes (short tons sold) (2)	336,000	—	336,000	—
NaOH (caustic soda) volumes (dry short tons sold) (3)	21,746	19,653	55,962	59,802
Total	388,127	53,952	487,537	155,918
Revenues (in thousands):				
NaHS revenues	$33,702	$37,054	$105,209	$103,680
NaOH (caustic soda) revenues	11,145	9,872	29,511	28,816
Revenues associated with Alkali Business	65,554	—	65,554	—
Other revenues	1,355	1,143	3,963	3,941
Total external segment revenues	$111,756	$48,069	$204,237	$136,437
Segment Margin (in thousands)	$30,031	$20,526	$63,864	$61,586
Average index price for NaOH per DST (1)	$647	$496	$613	$453

(1) Source: IHS Chemical. In the fourth quarter of 2016, IHS posted a non-market adjustment to previously posted US Caustic Soda Index prices. This adjustment is reflected in our disclosed index prices.

(2) Includes sales volumes from September 1, 2017, the date on which we acquired the Alkali Business.

(3) Caustic soda sales volumes also include volumes sold for the month of September from our new Alkali Business.

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Three Months Ended September 30, 2017 Compared with Three Months Ended September 30, 2016
Sodium minerals and sulfur services Segment Margin for the 2017 Quarter increased $9.5 million, or 46%. This increase is principally due to the inclusion of one month's contribution from the Alkali Business. This was partially offset by the results of our refinery services business and related NaHS and caustic soda activities. The 2017 Quarter results for these activities were in line with our expectations and include the effects of previously disclosed commercial discussions with certain of our host refineries and several NaHS customers, which resulted in extending the term and tenor of a large number of contractual relationships.
Nine Months Ended September 30, 2017 Compared with Nine Months Ended September 30, 2016
Sodium minerals and sulfur services Segment Margin for the first nine months of 2017 increased $2.3 million, or 4%. This increase is principally due to the inclusion of one month's contribution from the Alkali Business. This was partially offset by the results of our refinery services business and related NaHS and caustic soda activities. The nine months ended September 30, 2017 results for these activities were in line with our expectations and include the effects of previously disclosed commercial discussions with certain of our host refineries and several NaHS customers, which resulted in extending the term and tenor of a large number of contractual relationships.
Onshore Facilities and Transportation Segment
Our onshore facilities and transportation segment utilizes an integrated set of pipelines and terminals, as well as trucks, railcars, and barges to facilitate the movement of crude oil and refined products on behalf of producers, refiners and other customers. This segment includes crude oil and refined products pipelines, terminals, rail facilities and CO2 pipelines operating primarily within the United States Gulf Coast and Rocky Mountain crude oil markets. In addition, we utilize our railcar and trucking fleets that support the purchase and sale of gathered and bulk purchased crude oil, as well as purchased and sold refined products. Through these assets we offer our customers a full suite of services, including the following:

- facilitating the transportation of crude oil from producers to refineries and from owned and third party terminals to refiners via pipelines;
- transporting CO2 from natural and anthropogenic sources to crude oil fields owned by our customers;
- shipping crude oil and refined products to and from producers and refiners via trucks, pipelines, and railcars;
- loading and unloading railcars at our crude-by-rail terminals;
- storing and blending of crude oil and intermediate and finished refined products;
- purchasing/selling and/or transporting crude oil from the wellhead to markets for ultimate use in refining; and
- purchasing products from refiners, transporting those products to one of our terminals and blending those products to a quality that meets the requirements of our customers and selling those products (primarily fuel oil, asphalt and other heavy refined products) to wholesale markets.

We also use our terminal facilities to take advantage of contango market conditions, to gather and market crude oil, 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, sulfur content and metals content. 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 and transport crude oil meeting their requirements. The imbalances and inefficiencies relative to meeting the refiners' requirements may also provide opportunities for us to utilize our purchasing and logistical skills and assets to meet their demands. The pricing in the majority of our crude oil purchase contracts contains a market price component and a deduction to cover the cost of transportation and to provide us with a margin. Contracts sometimes contain a grade differential which considers the chemical 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 refined products marketing operations, we supply primarily fuel oil, asphalt and other heavy refined products to wholesale markets and some end-users such as paper mills and utilities. 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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Operating results from our onshore facilities and transportation segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Gathering, marketing, and logistics revenue	$229,002	$255,324	$663,988	$701,688
Crude oil and CO2 pipeline tariffs and revenues from direct financing leases of CO2 pipelines	17,261	13,219	48,606	44,773
Payments received under direct financing leases not included in income	1,751	1,586	5,127	4,645
Crude oil and petroleum products costs, excluding unrealized gains and losses from derivative transactions	(202,157)	(230,760)	(583,123)	(621,500)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(21,199)	(22,591)	(64,799)	(71,389)
Other	948	782	2,200	5,752
Segment Margin	$25,606	$17,560	$71,999	$63,969
Volumetric Data (average barrels per day):				
Onshore crude oil pipelines:				
Texas	45,329	11,529	28,418	41,708
Jay	13,716	15,119	14,480	14,494
Mississippi	8,104	9,503	8,478	10,607
Louisiana (1)	130,862	30,814	115,436	26,865
Wyoming	22,204	9,772	19,816	10,003
Onshore crude oil pipelines total	220,215	76,737	186,628	103,677
CO_2 pipeline (average Mcf/day):				
Free State	68,363	88,026	73,042	101,157
Crude oil and petroleum products sales:				
Total crude oil and petroleum products sales	52,082	64,292	49,255	66,725
Rail load/unload volumes (2)	42,221	13,091	55,010	13,344

(1) Total daily volume for the three months and nine months ended September 30, 2017 includes 66,048 and 54,974 barrels per day respectively of intermediate refined products associated with our Port of Baton Rouge Terminal pipelines which became operational in the fourth quarter of 2016. Additionally, this includes 19,574 and 6,925 barrels per day for the three months and nine months ended September 30, 2017 respectively of crude oil associated with our new Raceland Pipeline which became fully operational in the second quarter of 2017.

(2) Indicates total barrels for either loading or unloading at all rail facilities.

Three Months Ended September 30, 2017 Compared with Three Months Ended September 30, 2016

Segment Margin for our onshore facilities and transportation segment increased by $8.0 million, or 46%, between the two three month periods. In the 2017 Quarter, this increase is primarily attributable to the ramp up in volumes on our pipeline, rail and terminal infrastructure on our recently completed infrastructure in the Baton Rouge corridor. In addition, relative to the 2016 Quarter, we experienced an increase in volumes on our Texas pipeline system as the repurposing of our Houston area crude oil pipeline and expansion of our terminal infrastructure became operational in the second quarter of 2017.

Nine Months Ended September 30, 2017 Compared with Nine Months Ended September 30, 2016

Segment Margin for our onshore facilities and transportation segment increased by $8.0 million, or 13%, between the first nine months of 2017 and the first nine months of 2016. The nine months of 2017 include the effects of the ramp up in volumes on our pipeline, rail and terminal infrastructure on our recently completed infrastructure in the Baton Rouge corridor. This was principally offset by lower demand for our services in our historical back-to-back, or buy/sell, crude oil marketing business associated with aggregating and trucking crude oil from producers' leases to local or regional re-sale points. In addition, the first nine months of 2017 were negatively impacted by lower volumes on our Texas pipeline system, as the repurposing of our Houston area crude oil pipeline and expansion of our terminal infrastructure did not became operational until the second quarter of 2017 while the first nine months of 2016 included historical volumes on our legacy Texas pipeline system assets prior to the repurposing project for the majority of the period.

Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 86 barges (77 inland and 9 offshore) with a combined transportation capacity of 3.0 million barrels, 42 push/tow boats (33 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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues (in thousands):				
Inland freight revenues	$19,666	$22,108	$61,725	$66,402
Offshore freight revenues	17,468	23,271	54,912	66,240
Other rebill revenues (1)	11,400	9,906	35,401	27,288
Total segment revenues	$48,534	$55,285	$152,038	$159,930
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	$35,885	$38,588	$112,270	$106,235
Segment Margin (in thousands)	$12,649	$16,697	$39,768	$53,695
Fleet Utilization: (2)				
Inland Barge Utilization	90.8 %	87.6 %	90.5 %	91.4 %
Offshore Barge Utilization	99.3 %	96.2 %	98.4 %	91.2 %

(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 dry-docking.

Three Months Ended September 30, 2017 Compared with Three Months Ended September 30, 2016

Marine Transportation Segment Margin for the 2017 Quarter decreased $4.0 million, or 24%, from the 2016 Quarter. The decrease in Segment Margin is primarily due to lower day rates on our inland and offshore fleets (which offset higher utilization as adjusted for planned dry docking time). The M/T American Phoenix was also undergoing planned regulatory dry docking inspections for approximately one month during the 2017 Quarter, which negatively impacted Segment Margin. In our inland fleet, weaker demand continued to apply pressure on our rates, which we expect to continue into the fourth quarter. In our offshore barge fleet, as a number of our units have come off longer term contracts, we have continued to choose to primarily place them in spot service or short-term (less than a year) service, as we continue to believe the day rates currently being offered by the market are at, or approaching, cyclical lows.

Nine Months Ended September 30, 2017 Compared with Nine Months Ended September 30, 2016

Marine transportation Segment Margin for the first nine months of 2017 decreased $13.9 million, or 26%, from the first nine months of 2016. The decrease in Segment Margin is primarily due to lower day rates on our inland and offshore fleets (which offset higher utilization as adjusted for planned dry docking time). The M/T American Phoenix was also undergoing planned regulatory dry docking inspections for approximately one month during the 2017 Quarter, which negatively impacted Segment Margin. In our inland fleet, weaker demand continued to apply pressure on our rates, which we expect to continue into the fourth quarter. In our offshore barge fleet, as a number of our units have come off longer term contracts, we have continued to choose to primarily place them in spot service or short-term (less than a year) service, as we continue to believe the day rates currently being offered by the market are at, or approaching, cyclical lows.

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Other Costs, Interest, and Income Taxes

General and administrative expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below:				
Corporate	$7,456	$7,692	$24,735	$26,068
Segment	3,233	1,918	4,809	3,364
Equity-based compensation plan expense	(1,875)	1,239	(2,330)	3,918
Third party costs related to business development activities and growth projects	10,595	363	11,509	1,366
Total general and administrative expenses	$19,409	$11,212	$38,723	$34,716

Total general and administrative expenses increased $8.2 million and $4.0 million between the three and nine month periods primarily attributable to the third party financing, legal and accounting costs surrounding our acquisition of the Alkali Business in the 2017 Quarter. This was partially offset by the effects of changes in assumptions used to value our equity based compensation awards that are tied to our unit price.

Depreciation, depletion, and amortization expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Depreciation and depletion expense	$57,498	$46,909	$157,819	$135,428
Amortization of intangible assets	5,879	6,122	17,623	18,154
Amortization of CO2 volumetric production payments	355	1,234	1,011	3,218
Total depreciation, depletion and amortization expense	$63,732	$54,265	$176,453	$156,800

Total depreciation, depletion, and amortization expense increased $9.5 million and $19.7 million between the three and nine month periods primarily as a result of placing additional assets into service, including those acquired as a part of the Alkali Business in the 2017 Quarter.

Interest expense, net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$13,150	$11,076	$37,307	$31,117
Interest expense, senior unsecured notes	33,276	28,609	90,495	85,828
Amortization of debt issuance costs and discount	2,894	2,571	8,154	7,563
Capitalized interest	(1,932)	(7,521)	(13,839)	(19,851)
Net interest expense	$47,388	$34,735	$122,117	$104,657

Net interest expense increased $12.7 million and $17.5 million between the three and nine month periods primarily due to an increase in our average outstanding indebtedness from acquired and constructed assets, including the financing of the acquisition of the Alkali Business from Tronox in the 2017 Quarter. In addition, capitalized interest decreased as result of certain of our large organic growth projects being completed and placed into service during previous quarters in 2017.

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

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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 2017 Quarter included a $2.5 million unrealized loss on derivative positions as compared to a $0.6 million unrealized gain on derivative positions in the 2016 Quarter. Net income for the first nine months of 2017 included an unrealized loss on derivative positions, excluding fair value hedges, of $3.0 million. Net income for the first nine months of 2016 included an unrealized loss on derivative positions of $0.7 million.

Liquidity and Capital Resources

General

As of September 30, 2017, we had $314.7 million of remaining borrowing capacity under our $1.7 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 and trade receivables and payables;
- routine operating expenses;
- capital growth and maintenance projects;
- acquisitions of assets or businesses;
- payments related to servicing and reducing outstanding debt; and
- quarterly cash distributions to our unitholders.

As discussed in our recently announced strategic reallocation of capital, we intend to allocate more capital to debt repayments and growth opportunities (and less to current distributions).

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.

At September 30, 2017, our long-term debt totaled $4 billion, consisting of $1.4 billion outstanding under our credit facility (including $39 million borrowed under the inventory sublimit tranche) and $2.4 billion of senior unsecured notes, comprised of $350 million carrying amount due on February 15, 2021, $400 million carrying amount due on May 15, 2023, $350 million carrying amount due on June 15, 2024, $750 million carrying amount due August 1, 2022 and $550 million carrying amount due October 2025.

On August 14, 2017, we issued $550 million in aggregate principal amount of 6.50% senior unsecured notes due October 1, 2025. Interest payments are due April 1 and October 1 of each year with the initial interest payment due April 1, 2018. That issuance generated net proceeds of $540.1 million, net of issuance costs incurred. The net proceeds were used to fund a portion of the purchase price for our acquisition of the Alkali Business.

In July 2017, we amended our credit agreement to, among other things, make certain technical amendments related to the financing of our acquisition of the Alkali Business.

On March 24, 2017, we issued 4,600,000 Class A common units in a public offering at a price of $30.65 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 offering costs, of approximately $140.5 million from that offering.

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Class A Convertible Preferred Units
On September 1, 2017, we sold $750 million of Class A convertible preferred units in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the “Issue Price”) to two initial purchasers. Our general partner executed an amendment to our partnership agreement in connection therewith, which, among other things, authorized and established the rights and preferences of our preferred units. Our preferred units are a new class of security that ranks senior to all of our currently outstanding classes or series of limited partner interests with respect to distribution and/or liquidation rights. Holders of our preferred units vote on an as-converted basis with holders of our common units and have certain class voting rights, including with respect to any amendment to the partnership agreement that would adversely affect the rights, preferences or privileges, or otherwise modify the terms, of those preferred units.
Each of our preferred units accumulate quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374), subject to certain adjustments. With respect to any quarter ending on or prior to March 1, 2019, we have the option to pay to the holders of our preferred units the applicable distribution amount in cash, preferred units, or any combination thereof. If we elect to pay all or any portion of a quarterly distribution amount in preferred units, the number of such preferred units will equal the product of (i) the number of then outstanding preferred units and (ii) the quarterly rate. We have elected to pay the distribution amount attributable to the quarter ended on September 30, 2017 in preferred units. For each quarter ending after March 1, 2019, we must pay all distribution amounts in respect of our preferred units in cash.
For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our preferred units may make a one-time election to reset the quarterly distribution amount (a “Rate Reset Election”) to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 10% of the Issue Price. To become effective, the Rate Reset Election requires approval of holders of at least a majority of our then outstanding preferred units and such majority must include each of our initial purchasers (or any affiliate to whom they have transferred their preferred units) if such initial purchaser (including its affiliates) holds at least 25% of the then outstanding preferred units.
Upon the occurrence of a Rate Reset Election, we may redeem our preferred units for cash, in whole or in part (subject to certain minimum value limitations) for an amount per preferred unit equal to such preferred unit’s liquidation value (equal to the Issue Price plus any accrued and accumulated but unpaid distributions, plus a prorated portion of certain unpaid partial distributions in respect of the immediately preceding quarter and the current quarter) multiplied by (i) 110%, prior to September 1, 2024, and (ii) 105% thereafter. Each holder of our preferred units may elect to convert all or any portion of its preferred units into common units initially on a one-for-one basis (subject to customary adjustments and an adjustment for accrued and accumulated but unpaid distributions and limitations) at any time after September 1, 2019 (or earlier upon a change of control, liquidation, dissolution or winding up), provided that any conversion is for at least $50 million or such lesser amount if such conversion relates to all of a holder’s remaining preferred units or has otherwise been approved by us.
The Rate Reset Election of these preferred units represents and embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Unaudited Condensed Consolidated Balance Sheet. See further information in Note 14. The preferred units themselves are classified as mezzanine capital on our Condensed Consolidated Balance Sheet.
See Note 9 for additional information regarding our preferred units.
Equity Distribution Program and Shelf Registration Statements
We expect to issue additional equity and debt securities in the future to assist us in meeting our future liquidity requirements, particularly those related to opportunistically acquiring assets and businesses and constructing new facilities and refinancing outstanding debt.
In 2016, we implemented an equity distribution program that will allow us to consummate “at the market” offerings of common units from time to time through brokered transactions, which should help mitigate certain adverse consequences of underwritten offerings, including the downward pressure on the market price of our common units

and the expensive fees and other costs associated with such public offerings. We entered into an equity distribution agreement with a group of banks who will act as sales agents or principals for up to $400.0 million of our common units, if and when we should elect to issue additional common units from time to time, although there are limits to the amount of our “at the market” offerings the market can absorb from time to time. In connection with implementing our equity distribution program, we filed a universal shelf registration statement (our "EDP Shelf") with the SEC. Our EDP Shelf allows us to issue up to $1.0 billion of equity and debt securities, whether pursuant to our equity distribution program or otherwise. Our EDP Shelf will expire in October 2020. As of September 30, 2017, we have issued no additional units under this program.

We have another universal shelf registration statement (our "2015 Shelf") on file with the SEC. Our 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in connection with certain types of public offerings. However, the receptiveness of the capital markets to an offering of equity and/or debt securities cannot be assured and may be negatively impacted by, among other things, our long-term business prospects and other factors beyond our control, including market conditions. Our 2015 Shelf will expire in April 2018. We expect to file a replacement universal shelf registration statement before our 2015 Shelf expires.

Cash Flows from Operations

We generally utilize the cash flows we generate from our operations to fund our distributions and working capital needs. Excess funds that are generated are used to repay borrowings under 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, so we do not need to 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 those products to one of our storage facilities for further blending or sell those 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 our inventory 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 crude oil or petroleum products, we borrow under our credit facility (or use cash on hand) to pay for the crude 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 commodity 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 nine months ended September 30, 2017 and September 30, 2016. Net cash flows provided by our operating activities for the Nine Months Ended September 30, 2017 were $217.8 million compared to $228.4 million for the Nine Months Ended September 30, 2016. This decrease in operating cash flow is primarily due to an increase in working capital needs.

Capital Expenditures and Distributions Paid to our Unitholders

We use cash primarily for our operating expenses, working capital needs, debt service, acquisition activities, organic growth projects, maintenance capital expenditures and distributions we pay to our unitholders. We finance maintenance capital expenditures and smaller organic growth projects and distributions primarily with cash generated by our operations. We have historically funded material growth capital projects (including acquisitions and organic growth projects) with borrowings under our credit facility, equity issuances and/or issuances 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 nine months ended September 30, 2017 and September 30, 2016 is as follows:

	Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Capital expenditures for fixed and intangible assets:		
Maintenance capital expenditures:		
Offshore pipeline transportation assets	$4,093	$1,198
Sodium minerals and sulfur services assets	1,616	1,645
Marine transportation assets	17,439	11,358
Onshore facilities and transportation assets	3,213	9,478
Information technology systems	53	404
Total maintenance capital expenditures	26,414	24,083
Growth capital expenditures:		
Offshore pipeline transportation assets	$4,405	$7,777
Sodium minerals and sulfur services assets	5,276	—
Marine transportation assets	27,057	51,570
Onshore facilities and transportation assets	112,450	249,203
Information technology systems	114	6,398
Total growth capital expenditures	149,302	314,948
Total capital expenditures for fixed and intangible assets	175,716	339,031
Capital expenditures for acquisitions, inclusive of working capital acquired:		
Acquisition of Alkali business	1,325,000	—
Acquisition of remaining interest in Deepwater Gateway [1]	—	26,200
Total business combinations capital expenditures	1,325,000	26,200
Capital expenditures related to equity investees	—	—
Total capital expenditures	$1,500,716	$365,231

(1) Amount represents our purchase price for our purchase of the remaining 50% interest in Deepwater Gateway in the first quarter of 2016.

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. We continue to pursue a long-term growth strategy that may require significant capital.

Growth Capital Expenditures

We anticipate spending approximately $45.0 million, inclusive of capitalized interest, during the remainder of 2017 for projects currently under construction. The most significant of our recent projects are described below.

Baton Rouge Area Infrastructure Expansion

We are currently expanding our existing Baton Rouge area infrastructure to allow for greater capacity and flexibility in servicing our major refinery customer in the region. This expansion includes the construction of an additional 500,000 barrels of crude oil tankage at our existing Baton Rouge Terminal. Additionally, this expansion will include the upgrading of pumping and other infrastructure capabilities in order to allow for the efficient handling of expected increases in crude oil volumes received at our Baton Rouge area facilities. We expect these assets to become operational in the first quarter of 2018.

Houston Area Crude Oil Pipeline and Terminal Infrastructure

We have constructed new, and expanded existing, crude oil pipeline and terminal facilities in Webster, Texas and Texas City, Texas as a result of expanding our crude oil pipeline and terminal infrastructure in the Houston area. We have also constructed a new crude oil pipeline that delivers crude oil received from upstream crude oil pipelines (including CHOPS, which delivers crude oil originating in the deepwater Gulf of Mexico to the Texas City area) to our new Texas City Terminal, which connects to our existing 18-inch Webster to Texas City crude oil pipeline. Our new Texas City Terminal includes approximately 750,000 barrels of crude oil tankage. As a part of this project, we have also made the necessary upgrades on our existing 18-inch Webster to Texas City crude oil pipeline to reverse the direction of flow. The result of this expanded crude oil

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infrastructure allows additional optionality to Houston and Baytown area refineries, including the ExxonMobil Baytown refinery, its largest refinery in the U.S.A., and provides additional delivery outlets for other crude oil pipelines. These assets became operational in the second quarter of 2017.

Raceland Terminal and Crude Oil Pipeline

We have constructed a new crude oil terminal and pipeline in Raceland, Louisiana that connects to existing midstream infrastructure to provide further distribution to the Louisiana refining markets. Our new Raceland Terminal consists of 515,000 barrels of crude oil tankage and unit train unloading facilities capable of unloading up to two unit trains per day. We have also constructed a new crude oil pipeline that will deliver crude oil received from the Poseidon system, which currently delivers crude oil originating in the deepwater Gulf of Mexico to the Houma, Louisiana area, to our new Raceland Terminal for further distribution. These assets became fully operational at the end of the second quarter of 2017.

Inland Marine Barge Transportation Expansion

We ordered 28 new-build barges and 18 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 23 of those barges and 18 of those push boats through September 30, 2017. We expect to take delivery of those remaining barges periodically through 2017 and 2018.

Maintenance Capital Expenditures

Our slight increase in maintenance capital expenditures for the nine months ended September 30, 2017 Quarter as compared to the nine months ended September 30, 2016 Quarter principally relates to an increase in marine maintenance capital spending as a result of higher spending on certain vessel replacement parts and components. See further discussion under "Available Cash before Reserves" for how such maintenance capital utilization is reflected in our calculation of Available Cash before Reserves.

Proceeds from Assets Sales

The nine months ended September 30, 2017 include proceeds from asset sales of $39.2 million, as compared to proceeds of $3.3 million during the nine months ended September 30, 2016. This is principally comprised of the sale of certain non-core natural gas gathering and platform assets in the Gulf of Mexico in the second quarter of 2017. Subsequent to the end of the 2017 Quarter, we sold a non-core crude oil terminal facility in the Permian Basin, which completed a series of smaller asset sales totaling approximately $76 million (inclusive of non-core asset sales recognized through September 30, 2017).

Distributions to Unitholders

As recently announced as part of our strategic reallocation of capital, we reset our common unit distribution to $0.50 per common unit. On November 14, 2017, we will pay a distribution of $0.50 per common unit totaling $61.3 million with respect to the 2017 Quarter to common unitholders of record on October 31, 2017. Information on our recent distribution history is included in Note 9 to our Unaudited Condensed Consolidated Financial Statements.

With respect to our Class A Convertible Preferred Units, we have declared a payment-in-kind ("PIK") of the quarterly distribution, which will result in the issuance of an additional 162,234 Class A Convertible Preferred Units. This PIK amount, as pro-rated based on the period these units were outstanding, equates to a distribution of $0.2458 per Class A Convertible Preferred Unit for the 2017 Quarter, or $2.9496 annualized. These distributions will be payable on November 14, 2017 to unitholders holders of record at the close of business on November 3, 2017.

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Non-GAAP Financial Measure Reconciliations

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

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

	Three Months Ended September 30,	
	2017	2016
	(in thousands)	
Net income attributable to Genesis Energy, L.P.	$6,312	$32,101
Depreciation, depletion, amortization and accretion	66,436	57,103
Cash received from direct financing leases not included in income	1,751	1,586
Cash effects of sales of certain assets	967	120
Effects of distributable cash generated by equity method investees not included in income	7,136	9,063
Expenses related to acquiring or constructing growth capital assets	10,595	363
Unrealized loss (gain) on derivative transactions excluding fair value hedges, net of changes in inventory value	2,168	(571)
Maintenance capital utilized [1]	(3,375)	(1,885)
Non-cash tax expense	150	649
Differences in timing of cash receipts for certain contractual arrangements [2]	(5,847)	(3,624)
Other items, net	5,514	107
Available Cash before Reserves	91,807	95,012

(1) For a description of the term "maintenance capital utilized," please see the definition of the term "Available Cash Before Reserves" discussed below.

(2) Certain cash payments received from customers under certain of our minimum payment obligation contracts are not recognized as revenue under GAAP in the period in which such payments are received.

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	Three Months Ended September 30,	
	2017	2016
	(in thousands)	
Cash Flows from Operating Activities	$33,836	$124,725
Adjustments to reconcile net cash flow provided by operating activities to Available Cash before Reserves:		
Maintenance capital utilized [1]	(3,375)	(1,885)
Proceeds from certain asset sales	967	120
Amortization and writeoff of debt issuance costs, including premiums and discounts	(2,894)	(2,571)
Effects of available cash of equity method investees not included in operating cash flows	4,194	4,801
Net changes in components of operating assets and liabilities not included in calculation of Available Cash before Reserves	34,575	(26,834)
Non-cash effect of equity based compensation expense	3,566	(2,047)
Expenses related to acquiring or constructing assets that provide new sources of cash flow	10,595	363
Differences in timing of cash receipts for certain contractual arrangements [2]	(5,847)	(3,624)
Other items, net	16,190	1,964
Available Cash before Reserves	91,807	95,012

(1) For a description of the term "maintenance capital utilized," please see the definition of the term "Available Cash Before Reserves" discussed below.

(2) Certain cash payments received from customers under certain of our minimum payment obligation contracts are not recognized as revenue under GAAP in the period in which such payments are received.

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Non- GAAP Financial Measures
General

To help evaluate our business, we use the non-generally accepted accounting principle ("non-GAAP") financial measure of Available Cash before Reserves. We also present total Segment Margin as if it were a non-GAAP measure. 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 schedules above provide reconciliations of Available Cash before Reserves to its most directly comparable financial measures calculated in accordance with generally accepted accounting principles in the United States of America (GAAP). A reconciliation of total Segment Margin to net income is also included in our segment disclosure in Note 11 to our Unaudited Condensed Consolidated Financial Statements. 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 and total Segment Margin measures are just two 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.

Segment Margin

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. We define Segment Margin as revenues less product costs, operating expenses, and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees and certain litigation expenses that are not deducted to determine our Pro Forma Adjusted EBITDA under our revolving credit facility. Our Segment Margin definition also includes the non-income portion of payments received under direct financing leases and eliminates non-cash revenues, expenses, gains, losses and charges (such as depreciation and amortization, unrealized gain or loss on derivative transactions not designated as hedges for accounting purposes, gain or loss on sale of non-surplus assets and equity based compensation expense that is not settled in cash).

A reconciliation of total Segment Margin to net income is included in our segment disclosure in Note 9 to our Unaudited Condensed Consolidated Financial Statements, as well as previously in this Item 2.

Available Cash before Reserves

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.

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We define Available Cash before Reserves as net income as adjusted for certain items, some of the most significant of which tend to be (a) the elimination of certain non-cash revenues, expenses, gains, losses or charges (such as depreciation and amortization, unrealized gain or loss on derivative transactions not designated as hedges for accounting purposes, gain or loss on sale of non-surplus assets and equity compensation expense that is not settled in cash), (b) 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), (c) the elimination of expenses related to acquiring or constructing assets that provide new sources of cash flows, (d) certain litigation expenses that are not deducted in determining our Pro Forma Adjusted EBITDA under our senior secured credit facility, and (e) the subtraction of maintenance capital utilized, which is described in detail below.

Disclosure Format Relating to Maintenance Capital

We use a modified format relating to maintenance capital requirements because our maintenance capital expenditures vary 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 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.

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. Initially, substantially all of our maintenance capital expenditures were (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.

As we exist today, 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 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 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

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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 did not initially use 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.

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, 2016.

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, 2016, 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, natural gas, NaHS, caustic soda and CO_2, 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, natural gas 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, regulations regarding qualifying income, 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;

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- 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, which may reduce our earnings, profitability and cash flow;
- changes in global economic conditions, including capital and credit markets conditions, inflation and interest rates;
- natural disasters, accidents or terrorism;
- 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, 2016. These risks may also be specifically described in our Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K (or any amendments to those reports) 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, 2016. 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 third quarter of 2017 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, 2016. There have been no material developments in legal proceedings since the filing of such Form 10-K.

Item 1A. Risk Factors

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, 2016, except as supplemented by our quarterly Reports on Form 10-Q and Current Reports on Form 8-K and Form 8-K/A.

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016, 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.

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

There were no sales of unregistered equity securities during the 2017 Quarter other than as previously included in our Current Report on Form 8-K filed on September 7, 2017.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Information regarding mine safety and other regulatory action at our mine in Green River, Wyoming is including in Exhibit 95 to this Form 10-Q.

Item 5. Other Information

None.

Item 6. Exhibits.

(a) Exhibits

2.1	Stock Purchase Agreement, dated August 2, 2017, by and among Genesis Energy, L.P., Tronox US Holdings, Inc., Tronox Alkali Corporation and, for the purposes set forth therein, Tronox Limited (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated August 7, 2017, 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 of the 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 the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 001-12295).
3.3	Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 5.1 to the Company's Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
3.4	First Amendment to Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P., dated September 1, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated September 7, 2017, File No. 001-12295).
3.5	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 the Company's Current Report on Form 8-K dated January 7, 2009, File No. 001-12295).

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3.6	Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated January 7, 2009, File No. 001-12295).
3.7	Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 5.2 to the Company's Current Report on 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 the Company's Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-12295).
4.2	Eighth Supplemental Indenture, dated as of August 14, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee to the Indenture dated as of May 21, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference from Exhibit 4.2 to the Company's Current Report on Form 8-K filed on August 14, 2017, File No. 001-12295).
4.3	Registration Rights Agreement, dated September 1, 2017, by and among Genesis Energy, L.P., GSO Rodeo Holdings LP and Rodeo Finance Aggregator LLC (incorporated by reference from Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295).
10.1	Class A Convertible Preferred Unit Purchase Agreement, dated August 2, 2017, by and between Genesis Energy, L.P., and the purchasers named on Schedule A thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 7, 2017, File No. 001-12295).
10.2	Sixth Amendment to the Fourth Amended and Restated Credit Agreement, dated July 28, 2017, among Genesis Energy, L.P., as borrower, Wells Fargo Bank National Association, as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 7, 2017, File No. 001-12295).
10.3	Board Observer Agreement, dated September 1, 2017, by and among Genesis Energy, L.P., GSO Rodeo Holdings LP and Rodeo Finance Aggregator LLC (incorporated by reference from Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295).
*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.
*95	Mine Safety Disclosures
*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: November 3, 2017 By: /s/ ROBERT V. DEERE
Robert V. Deere
Chief Financial Officer