GENESIS ENERGY LP
Form 10-Q
November 01, 2018
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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, 2018
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	76-0513049
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
919 Milam, Suite 2100, Houston, TX	77002
(Address of principal executive offices)	(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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit 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 ¨	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 1, 2018.

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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, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 11,878	$ 9,041
Accounts receivable - trade, net	365,646	495,449
Inventories	85,722	88,653
Assets held for sale	255,519	—
Other	42,659	42,890
Total current assets	761,424	636,033
FIXED ASSETS, at cost	5,405,984	5,601,015
Less: Accumulated depreciation	(882,833)	(734,986)
Net fixed assets	4,523,151	4,866,029
MINERAL LEASEHOLDS, net of accumulated depletion	561,593	564,506
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	119,093	125,283
EQUITY INVESTEES	356,468	381,550
INTANGIBLE ASSETS, net of amortization	168,291	182,406
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	120,102	56,628
TOTAL ASSETS	$ 6,935,168	$ 7,137,481
LIABILITIES AND CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 194,489	$ 270,855
Accrued liabilities	235,517	185,409
Total current liabilities	430,006	456,264
SENIOR SECURED CREDIT FACILITY	1,220,700	1,099,200
SENIOR UNSECURED NOTES, net of debt issuance costs	2,460,486	2,598,918
DEFERRED TAX LIABILITIES	12,293	11,913
OTHER LONG-TERM LIABILITIES	275,823	256,571
Total liabilities	4,399,308	4,422,866
MEZZANINE CAPITAL:		
Class A Convertible Preferred Units, 23,914,890 and 22,411,728 issued and outstanding at September 30, 2018 and December 31, 2017, respectively	744,727	697,151
PARTNERS' CAPITAL:		
Common unitholders, 122,579,218 units issued and outstanding at September 30, 2018 and December 31, 2017	1,799,409	2,026,147
Accumulated other comprehensive loss	(604)	(604)
Noncontrolling interests	(7,672)	(8,079)
Total partners' capital	1,791,133	2,017,464
TOTAL LIABILITIES, MEZZANINE CAPITAL AND PARTNERS' CAPITAL	$ 6,935,168	$ 7,137,481

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,	
	2018	2017	2018	2017
REVENUES:				
Offshore pipeline transportation services	70,115	80,671	213,344	243,437
Sodium minerals and sulfur services	291,722	109,765	876,513	197,879
Marine transportation	56,296	48,534	161,410	152,038
Onshore facilities and transportation	327,145	247,144	972,207	714,974
Total revenues	745,278	486,114	2,223,474	1,308,328
COSTS AND EXPENSES:				
Onshore facilities and transportation product costs	273,251	202,047	834,128	582,535
Onshore facilities and transportation operating costs	22,005	23,982	67,346	80,160
Marine transportation operating costs	44,195	35,789	126,259	111,980
Sodium minerals and sulfur services operating costs	229,204	79,365	685,219	133,335
Offshore pipeline transportation operating costs	17,753	18,690	53,533	54,682
General and administrative	24,209	19,409	49,412	38,723
Depreciation, depletion and amortization	91,876	63,732	244,811	176,453
Gain on sale of assets	(3,363)	—	(3,363)	(26,684)
Total costs and expenses	699,130	443,014	2,057,345	1,151,184
OPERATING INCOME	46,148	43,100	166,129	157,144
Equity in earnings of equity investees	9,492	13,044	28,388	34,805
Interest expense	(58,819)	(47,388)	(172,864)	(122,117)
Other income (expense)	1,828	(2,276)	(3,604)	(2,276)
Income (loss) before income taxes	(1,351)	6,480	18,049	67,556
Income tax expense	(283)	(320)	(914)	(878)
NET INCOME (LOSS)	(1,634)	6,160	17,135	66,678
Net loss attributable to noncontrolling interests	1,311	152	1,573	457
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$(323)	$6,312	$18,708	$67,135
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(17,635)	(5,469)	(51,780)	(5,469)
NET INCOME(LOSS) AVAILABLE TO COMMON UNITHOLDERS	$(17,958)	$843	$(33,072)	$61,666
NET INCOME(LOSS) PER COMMON UNIT (Note 11):				
Basic and Diluted	$(0.15)	$0.01	$(0.27)	$0.51
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:				
Basic and Diluted	122,579	122,579	122,579	121,198

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 COMPREHENSIVE INCOME
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income (loss)	$(1,634)	$6,160	$17,135	$66,678
Other comprehensive loss:				
Change in benefit plan liability	—	—	—	—
Total Comprehensive income (loss)	(1,634)	6,160	17,135	66,678
Comprehensive loss attributable to non-controlling interests	1,311	152	1,573	457
Comprehensive income (loss) attributable to Genesis Energy, L.P.	$(323)	$6,312	$18,708	$67,135

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	Accumulated Other Comprehensive Loss	Total
Partners' capital, December 31, 2017	122,579	$2,026,147	$ (8,079)	$ (604)	$2,017,464
Impact of adoption of ASC 606	—	(3,550)	—	—	(3,550)
Partners' capital, January 1, 2018	122,579	2,022,597	(8,079)	(604)	2,013,914
Net income (loss)	—	18,708	(1,573)	—	17,135
Cash distributions to partners	—	(191,224)	—	—	(191,224)
Cash contributions from noncontrolling interests	—	—	1,980	—	1,980
Distributions to Class A Convertible Preferred unitholders	—	(50,672)	—	—	(50,672)
Partners' capital, September 30, 2018	122,579	$1,799,409	$ (7,672)	$ (604)	$1,791,133

	Number of Common Units	Partners' Capital	Noncontrolling Interest	Accumulated Other Comprehensive Loss	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

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, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$17,135	$66,678
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation, depletion and amortization	244,811	176,453
Provision for leased items no longer in use	—	12,589
Gain on sale of assets	(3,363)	(26,684)
Amortization and write-off of debt issuance costs and discount	9,489	8,154
Amortization of unearned income and initial direct costs on direct financing leases	(9,847)	(10,374)
Payments received under direct financing leases	15,501	15,501
Equity in earnings of investments in equity investees	(28,388)	(34,805)
Cash distributions of earnings of equity investees	28,992	34,454
Non-cash effect of long-term incentive compensation plans	3,240	(5,524)
Deferred and other tax liabilities	380	508
Unrealized loss on derivative transactions	1,285	3,040
Other, net	999	(7,338)
Net changes in components of operating assets and liabilities (Note 14)	27,330	(26,262)
Net cash provided by operating activities	307,564	206,390
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(152,868)	(182,653)
Cash distributions received from equity investees - return of investment	26,042	25,917
Investments in equity investees	(2,960)	—
Acquisitions	—	(1,325,759)
Contributions in aid of construction costs	—	124
Proceeds from asset sales	36,859	39,204
Net cash used in investing activities	(92,927)	(1,443,167)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on senior secured credit facility	759,800	1,247,700
Repayments on senior secured credit facility	(638,300)	(1,153,400)
Proceeds from issuance of senior unsecured notes	—	550,000
Proceeds from issuance of Class A convertible preferred units, net	—	729,958
Repayment of senior unsecured notes	(145,170)	—
Debt issuance costs	(242)	(17,808)
Issuance of common units for cash, net	—	140,513
Contributions from noncontrolling interests	1,980	1,850
Distributions to common unitholders	(191,224)	(260,586)
Other, net	1,356	1,215
Net cash provided by (used in) financing activities	(211,800)	1,239,442
Net increase in cash and cash equivalents	2,837	2,665
Cash and cash equivalents at beginning of period	9,041	7,029
Cash and cash equivalents at end of period	$11,878	$9,694

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 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 our trona and trona-based exploring, mining, processing, producing, marketing and selling business (our "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 Class A Convertible Preferred units (our "preferred units"), a $550 million public offering of notes, our revolving credit facility, and cash on hand. We report the results of our Alkali Business in our sodium minerals and sulfur services segment, which includes our Alkali Business as well as our legacy refinery services operations.
We currently manage our businesses through the following four divisions that constitute our reportable segments:

- 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; and
- Marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America.

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 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, 2017.
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
We have adopted guidance under ASC Topic 606, Revenue from Contracts with Customers, and all related ASUs (collectively "ASC 606") as of January 1, 2018 utilizing the modified retrospective method of adoption. The adoption date for our material equity method investment in the Poseidon Oil Pipeline Company, LLC will follow the non-public business entity adoption date of January 1, 2019 for its stand-alone financial statements. Refer to Note 3

for further details.

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

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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.
Our team has reviewed the practical expedients we expect to apply as part of the implementation of the new standard. In July 2018, the FASB issued ASU 2018-11 as a targeted improvement on the new leasing standard, which provides an additional (and optional) method to adopt the new leasing standard. Under this new transition method, an entity will only apply the new lease standard at the date of adoption while comparative periods will be presented under the previous lease guidance (Topic 840). We plan to adopt this method for our transition.
Additionally, we currently plan to elect to take the "package" of practical expedients set out in the standard, which must be elected together. The items within the package stipulate that an entity need not reassess: (1) if expired or existing contracts contain leases, (2) lease classification for previously assessed leases under ASC 840, and (3) initial direct costs for existing leases. The standard allows for a practical expedient relating to the separation of lease and non-lease components when applying ASC 842. This expedient is made as a policy election based on asset class and is applied to all items within the class. We have elected to adopt this expedient as part of our transition and implementation. Our team is still evaluating which asset classes will have such a policy election. As it relates to easements and right of ways, a practical expedient is permitted where companies can elect to continue to apply its current accounting policy for all land easements that exist or expire prior to the adoption date. We plan to take this expedient and will continue to apply our current accounting treatment to existing easements. An additional expedient offered by the new standard is the hindsight expedient, which allows an entity to use hindsight when determining a lease term, including options to renew or terminate as well as impairment for right-of-use assets. We do not plan to utilize this practical expedient.
Lastly, our implementation team is in the process of identifying our complete lease population and evaluating the application of 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 have adopted this guidance as of January 1, 2018 using the retrospective transition method to each period presented on the Consolidated Statements of Cash Flows. We reclassified $11.4 million from operating cash flows to investing cash flows for the nine months ended September 30, 2017.
In March 2017, the FASB issued ASU 2017-07, Compensation-Retirement Benefits (Topic 715). ASU 2017-07 requires employers to separate the service cost component from the other components of net benefit cost in the period. The new standard requires the other components of net benefit costs (excluding service costs), be reclassified to "Other expense" from "General and administrative." We adopted this standard as of January 1, 2018. This standard is applied retrospectively. The effect was not material to our financial statements for the three and nine months ended September 30, 2018.

3. Revenue Recognition
Adoption of ASC 606 and its related Transition Effects
The modified retrospective method of adoption required us to apply ASC 606 to all new revenue contracts entered into after January 1, 2018 and revenue contracts that were not completed as of January 1, 2018. Our consolidated revenues for periods prior to January 1, 2018 were not revised and the cumulative effect of our adoption of ASC 606 was recorded as an adjustment to partners' capital at January 1, 2018. Based on this application, the following adjustments were made to our consolidated balance sheet as of January 1, 2018:

	December 31, 2017	Adjustments	January 1, 2018
ASSETS			
Accounts receivable - trade, net	$495,449	$ (48,028)	$447,421

Inventories	88,653	5,138	93,791
Other assets, net of amortization	56,628	59,204	115,832
LIABILITIES AND CAPITAL			
Other long-term liabilities	256,571	19,864	276,435
Partners' capital	2,026,147	(3,550)	2,022,597

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Current Impact of New Revenue Recognition Guidance
The tables below summarize the impact of adoption on our unaudited condensed consolidated balance sheet and statement of operations as of and for the three and nine months ended September 30, 2018:

	As of September 30, 2018		
Unaudited Condensed Consolidated Balance Sheet	As Reported	Without adoption of ASC 606	Effect of Change Increase/(Decrease)
ASSETS			
Accounts receivable-trade, net	$365,646	$413,674	$ (48,028)
Inventories	85,722	83,329	2,393
Other Assets, net of amortization	120,102	50,742	69,360
LIABILITIES AND CAPITAL			
Other Long-Term Liabilities	275,823	251,075	24,748
Partners' Capital	1,799,409	1,800,432	(1,023)

	Three months ended September 30, 2018			Nine months ended September 30, 2018		
Unaudited Condensed Consolidated Statement of Operations	As Reported	Without adoption of ASC 606	Effect of Change Increase/(Decrease)	As Reported	Without adoption of ASC 606	Effect of Change Increase/(Decrease)
Offshore pipeline transportation services	$70,115	$69,323	$ 792	$213,344	$208,073	$ 5,271
Sodium minerals and sulfur services	291,722	268,207	23,515	876,513	801,323	75,190
Marine transportation	56,296	56,296	—	161,410	161,410	—
Onshore facilities and transportation	327,145	327,145	—	972,207	972,207	—
Total revenues	745,278	720,971	24,307	2,223,474	2,143,013	80,461
Onshore facilities and transportation product costs	273,251	273,251	—	834,128	834,128	—
Onshore facilities and transportation operating costs	22,005	22,005	—	67,346	67,346	—
Marine transportation operating costs	44,195	44,195	—	126,259	126,259	—
Sodium minerals and sulfur services operating costs	229,204	204,013	25,191	685,219	607,285	77,934
Offshore pipeline transportation operating costs	17,753	17,753	—	53,533	53,533	—
OPERATING INCOME	46,148	47,032	(884)	166,129	163,602	2,527

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The effects of changes pursuant to ASC 606 in the tables above are attributable to our offshore pipeline transportation services operating segment and our sodium minerals and sulfur services operating segment.

In our offshore pipeline transportation services segment, we have certain contracts with customers that contain tiered pricing structures that are dependent upon reaching certain cumulative milestones of throughput volumes on our pipelines. In addition, we have a contract that contains fixed and variable consideration for us to stand ready and provide reservation capacity for a fixed minimum quantity on our pipeline. Pursuant to the new guidance, we have allocated our estimated total transaction price over the life of the contract to the related performance obligation and recognized the effects in our Consolidated Financial Statements. In our sodium minerals and sulfur services operating segment, specifically our legacy refinery services business, we have two distinct performance obligations, including the completion of our refinery sulfur removal process, for which we receive in-kind consideration, and our sale of NaHS to our customers. Due to this, we have recorded revenue and the related cost of sales in the Consolidated Financial Statements for the three and nine months ended September 30, 2018 for services performed for the in-kind consideration for our services. Further discussion of our performance obligations by type and segment are below.

Revenue from Contracts with Customers

The following table reflects the disaggregation of our revenues by major category for the three and nine months ended September 30, 2018:

Three Months Ended September 30,	Onshore Facilities & Transportation	Sodium Minerals & Sulfur Services	Offshore Pipeline Transportation	Marine Transportation	Consolidated
Fee-based revenues	$42,188	$—	$ 70,115	$ 56,296	$ 168,599
Product Sales	284,957	268,207	—	—	553,164
Refinery Services	—	23,515	—	—	23,515
	$327,145	$291,722	$ 70,115	$ 56,296	$ 745,278

Nine Months Ended September 30,	Onshore Facilities & Transportation	Sodium Minerals & Sulfur Services	Offshore Pipeline Transportation	Marine Transportation	Consolidated
Fee-based revenues	$107,536	$—	$ 213,344	$ 161,410	$482,290
Product Sales	864,671	801,323	—	—	1,665,994
Refinery Services	—	75,190	—	—	75,190
	$972,207	$876,513	$ 213,344	$ 161,410	$2,223,474

The Company recognizes revenue upon the satisfaction of its performance obligations under its contracts. The timing of revenue recognition varies for the revenue streams described in more detail below. In general, the timing includes recognition of revenue over time as services are being performed as well as recognition of revenue at a point in time, for delivery of products.

Fee-based Revenues

We provide a variety of fee-based transportation and logistics services to our customers across several of our reportable segments as outlined below.

Service contracts generally contain a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over the contract period, and therefore qualify as a single performance obligation that is satisfied over time. The customer receives and consumes the benefit of our services simultaneous with the provision of those services.

Offshore Pipeline Transportation

Revenue from our offshore pipelines is generally based upon a fixed fee per unit of volume (typically per Mcf of natural gas or per barrel of crude oil) gathered, transported, or processed for each volume delivered. Fees are based either on contractual arrangements or tariffs regulated by the FERC. These contracts include a single performance obligation to stand ready, on a

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monthly basis, to provide capacity on our assets. Revenue associated with these fee-based services is recognized as volumes are delivered over the performance obligation period.

In addition to the offshore pipeline transportation revenue discussed above, we also have certain contracts with customers in which we earn either demand-type fees or firm capacity reservation fees. These fees are charged to a customer regardless of the volume the customer actually delivers to the platform or through the pipeline.

In addition to these offshore pipeline transportation services revenue streams, we also have certain customer contracts in which the transportation fee has a tiered pricing structure based on cumulative milestones of throughput on the related pipeline asset and contract, or on a specified date. The performance obligation for these contracts is to transport, gather or process commodity volumes for the customer based on firm (stand ready) service or from monthly nominations made by our customers, which can also be on an interruptible basis. While our transportation rate changes when milestones are achieved for certain cumulative throughput, the performance obligation satisfied by us does not change throughout the life of the contract. Therefore revenue is recognized on an average rate basis throughout the life of the contract. We have estimated the total consideration to be received under the contract beginning at the contract inception date based on the estimated volumes (including certain minimum volumes we are required to stand ready for), price indexing, estimated production or contracted volumes, and the contract period. We have constrained the estimates of variable consideration such that it is probable that a significant reversal of previously recognized revenue will not occur throughout the life of the contract. These estimates will be reassessed at each reporting period as required. Billings to our customers are reflected at the contract rate. The difference between the consideration received from our customers from invoicing compared to the revenue recognized creates a contract asset or liability. In circumstances where the estimated average contract rate is less than the billed current price tier in the contract, we will recognize a contract liability. In circumstances where the estimated average contract rate is higher than the billed current price tier in the contract, we will recognize a contract asset.

Onshore Facilities and Transportation
Within our onshore facilities and transportation segment, we provide our customers with pipeline transportation, terminalling services, and rail loading/unloading services, among others, primarily on a per barrel fee basis.

Revenues from contracts for the transportation of crude oil by our pipelines are based on actual volumes at a published tariff and some contain minimum throughput provisions which reset within one year. We recognize revenues for transportation and other services over the performance obligation period, which is the contract term. Revenues for both firm and interruptible transportation and other services are recognized over time as the product is delivered to the agreed upon delivery point or at the point of receipt because they specifically relate to our efforts to transfer the distinct services.

Pricing for our services is determined through a variety of mechanisms, including specified contract pricing or regulated tariff pricing. Consideration to be received by us under these contracts is variable, as the total volume of the commodity to be transported is unknown at contract inception. At the end of a day or month (as specified in the contract), both the price and volume are known (or “fixed”) in order to allow us to accurately calculate the amount of consideration we are entitled to invoice. The measurement of these services and invoicing occurs on a monthly basis.

Pipeline Loss Allowances
In order to compensate us for bearing the risk of volumetric losses of crude oil in transit in our pipelines (for our onshore and offshore pipelines) due to temperature, crude quality, and the inherent difficulties of measurement of liquids in a pipeline, our tariffs and agreements include the right for us to make volumetric deductions from the customer for quality and volumetric fluctuations. We refer to these deductions as pipeline loss allowances ("PLA"). We compare these allowances to the actual volumetric gains and losses of the pipeline and the net gain or loss is recorded as revenue or a reduction of revenue. As the allowance is related to our pipeline transportation services, the

performance obligation is the obligation to transport and deliver the barrels and is considered a single obligation.

When net gains occur, we have crude oil inventory. When net losses occur, we reduce any recorded inventory on hand and record a liability for the purchase of crude oil required to replace the lost volumes. Under ASC 606, we record excess oil as non-cash consideration at the lower of the recorded value or the market value and include this amount in the transaction price. The crude oil in inventory can then be sold at current prevailing market prices, resulting in additional revenue if the sales price exceeds the inventory value when control transfers to the customer.

Marine Transportation

Our marine transportation business consists of revenues from the inland and offshore marine transportation of heavy refined petroleum products, asphalt and crude oil, using our barges or vessels. This revenue is recognized over the passage of

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time of individual trips as determined on an individual contract basis. Revenue from these contracts is typically based on a set day-rate or a set fee per cargo movement. The costs of fuel and certain other operational costs may be directly reimbursed by the customer, if stipulated in the contract.

A performance obligation is driven by providing transportation services using our vessels for a single day either under a term or spot based contract. The transaction price is usually fixed per the contract either as a day rate or as a lump sum to be allocated over days required to complete the service. Revenue is recognizable as the transportation service utilizing our vessels occurs, as the customer simultaneously receives and consumes these services as they are provided. If provided in the contract, certain items such as fuel or operational costs can be rebilled to the customer in the same period in which the costs are incurred. In the event the timing of a trip to provide our services crosses a reporting period under a lump sum fee contract, the revenue earned is accrued based on the progress completed in the current period on the related performance obligation as we are entitled to payment for each day. Customer invoicing occurs at the completion of a trip, or earlier at the customer's request.

Product Sales

Sodium Minerals and Sulfur Services

Product sales in our sodium minerals and sulfur services segment primarily involve the sales of caustic soda, NaHS, soda ash and other alkali products. As it relates to revenue recognition, these sales transactions contain a single performance obligation, which is the delivery of the product to the customer at the agreed upon point of sale. For some transactions, control of product transfers to the customer at the shipping point, but we are obligated to arrange for shipment of the product as directed by the customer. Rather than treat these shipping activities as separate performance obligations, our policy is to account for them as fulfillment costs in accordance with ASC 606.

The transaction price for these product sales are determined by specific contracts, typically at a fixed rate or based on a market or indexed rate. This pricing is known, or is "fixed," at the time of revenue recognition. Invoicing and related payment terms are in accordance with industry standard or contract specification based on final pricing. The entirety of the transaction price is allocated to the performance obligation which is delivery of the product at the agreed upon point of sale. As this type of revenue is earned at a point in time, there is no allocation of transaction price to future performance obligations.

Onshore Facilities and Transportation

Product sales in our onshore facilities and transportation segment primarily involve the sales of crude oil and petroleum products. These contracts contain a single performance obligation, which is the delivery of the product to the customer at a specified location. These contracts are settled on a monthly basis for term contracts, or on a spot basis. Invoicing and related payment terms are in accordance with industry standard or contract specification based on final pricing.

Pricing is designated within the contracts and is either fixed, index-based or formulaic, utilizing an average price for the month or for a specified range of days, regardless of when delivery occurs. In either case, pricing is known at the time of invoicing. The entirety of the consideration is allocated to a single performance obligation which is delivery of the product to a specified location. As this type of revenue is earned at a point in time, there is no allocation of transaction price to future performance obligations.

Refinery Services

Our refinery services business primarily provides sulfur extraction services to refiners' high sulfur (or "sour") gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses caustic soda to act as a scrubbing agent under prescribed temperature and pressure to remove sulfur. The technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS. Units of NaHS are produced ratably as a gas stream is processed. We obtain control and ownership of the NaHS immediately upon production which constitutes the sole consideration received for our sulfur removal services. We later market this product to third parties as part of our product sales, as described above. As part of some of our arrangements, we pay a refinery access fee (“RSA fee”) for any benefits received by virtue of our plant’s proximity to the customer’s refinery. Our RSA fee is recorded as a reduction of revenue.

Providing sulfur removal services is the singular performance obligation in our refinery service agreements. As our customers simultaneously receive and consume the refinery service benefits, control is transferred and revenue is recognized over time based on the extent of progress towards completion of the performance obligations. We use units of NaHS produced during a period to measure progress as the amount we receive corresponds directly with the efforts to provide our services completed to date. The transaction price for each performance obligation is determined using the fair value of a unit of NaHS on the contract inception date for each refinery services agreement. Accordingly, we record the value of NaHS received as non-cash consideration in inventory until it is subsequently sold to our customers (see Product Sales, above).

Contract Assets and Liabilities

The table below depicts our contract asset and liability balances at January 1, 2018 and September 30, 2018:

	Contract Assets Non-Current	Contract Liabilities Non-Current
Balance at January 1, 2018	$ 59,204	$ 19,864
Balance at September 30, 2018	69,360	24,748

During the nine months ended September 30, 2018, there were no balances that were previously classified as contract liabilities at the beginning of the period that were recognized as revenues. Accounts receivable-trade, net does not include consideration received in kind from our refinery services process. We did not have any contract modifications during the period that would affect our contract asset and liability balances.

Transaction Price Allocations to Remaining Performance Obligations

We are required to disclose the amount of our transaction prices that are allocated to unsatisfied performance obligations as of September 30, 2018. However, ASC 606 does provide the following practical expedients and exemptions that we utilized:

1) Performance obligations that are part of a contract with an expected duration of one year or less;

2) Revenue recognized from the satisfaction of performance obligations where we have a right to consideration in an amount that corresponds directly with the value provided to customers; and

3) Contracts that contain variable consideration, such as index-based pricing or variable volumes, that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that is part of a series.

We apply these practical expedients and exemptions to our revenue streams recognized over time. The majority of our contracts qualify for one of these expedients or exemptions. After considering these practical expedients and identifying the remaining contract types that involve revenue recognition over a long-term period and include long-term fixed consideration (adjusted for indexing as required), we determined our allocations of transaction price that relate to unsatisfied performance obligations. As it relates to our tiered pricing offshore transportation contracts, we provide firm capacity for both fixed and variable consideration over a long term period. Therefore, we have allocated the remaining contract value (as estimated and discussed above) to future periods.

Similarly, in our marine transportation segment, our contract related to our M/T American Phoenix contains minimum fixed consideration over the life of the contract, which ends in September 2020. In our onshore facilities and transportation segment, we have certain contractual arrangements in which we receive fixed minimum payments for our obligation to provide minimum capacity on our pipelines and related assets.

The following chart depicts how we expect to recognize revenues for future periods related to these contracts:

	Offshore Pipeline Transportation	Marine Transportation	Onshore Facilities and Transportation
Remainder of 2018	$ 21,154	$ 6,808	$ 14,297
2019	73,918	27,010	57,090
2020	50,883	20,128	57,090

2021	34,261	—	20,139
2022	22,558	—	4,283
Thereafter	134,623	—	—
Total	$ 337,397	$ 53,946	$ 152,899

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4. Acquisition

Acquisition

Alkali Business

On September 1, 2017, we acquired our Alkali Business for approximately $1.325 billion (inclusive of approximately $105 million in working capital). Our Alkali Business produces natural soda ash, also known as sodium carbonate (Na_2CO_3), a 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 our 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. Those fair values were developed by management with the assistance of a third-party valuation firm. Our finalized purchase price allocation remains unchanged from what was disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017.

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, 2018	Nine Months Ended September 30, 2018
Revenues	$ 208,742	628,672
Net Income Attributable to Genesis Energy, L.P.	$ 29,536	91,680

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, 2017 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 our Alkali Business acquisition been completed on January 1, 2017. Pro forma net income includes the effects of distributions on our preferred units and interest expense on incremental borrowings. The dilutive effect of our preferred units is calculated using the if-converted method.

	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
Pro forma consolidated financial operating results:		
Revenues	$615,289	$1,829,389
Net Income Attributable to Genesis Energy, L.P.	10,955	92,880
Net Income (Loss) Available to Common Unitholders	(6,178)	42,575

Basic and diluted earnings per common unit:		
As reported net income per common unit	$0.01	$0.51
Pro forma net income (loss) per common unit	$(0.05)	$0.35

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5. Inventories
The major components of inventories were as follows:

	September 30, 2018	December 31, 2017
Petroleum products	$ 21,082	$ 8,731
Crude oil	16,493	29,873
Caustic soda	8,030	5,755
NaHS	9,682	8,277
Raw materials - Alkali operations	5,592	4,550
Work-in-process - Alkali operations	2,820	7,355
Finished goods, net - Alkali operations	11,526	14,075
Materials and supplies, net - Alkali operations	10,496	10,030
Other	1	7
Total	$ 85,722	$ 88,653

Inventories are valued at the lower of cost or net realizable value. The net realizable value of inventories were below recorded costs by approximately $0.1 million as of September 30, 2018 without similar adjustments required as of December 31, 2017.

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6. Fixed Assets and Mineral Leaseholds
Fixed Assets
Fixed assets consisted of the following:

	September 30, 2018	December 31, 2017
Crude oil pipelines and natural gas pipelines and related assets	$ 2,900,469	$ 3,028,657
Alkali facilities, machinery, and equipment	515,226	497,601
Onshore facilities, machinery, and equipment	638,726	692,364
Transportation equipment	20,352	21,483
Marine vessels	946,377	918,953
Land, buildings and improvements	220,823	223,186
Office equipment, furniture and fixtures	18,898	18,112
Construction in progress	97,313	151,768
Other	47,800	48,891
Fixed assets, at cost	5,405,984	5,601,015
Less: Accumulated depreciation	(882,833)	(734,986)
Net fixed assets	$ 4,523,151	$ 4,866,029

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

	September 30, 2018	December 31, 2017
Mineral leaseholds	$ 566,019	$ 566,019
Less: Accumulated depletion	(4,426)	(1,513)
Mineral leaseholds, net	$ 561,593	$ 564,506

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Depreciation expense	$ 85,282	$ 57,117	$ 224,546	$ 157,438
Depletion expense	722	381	2,913	381

Assets Held for Sale
On August 7, 2018, we granted a third party a time-limited option to acquire certain of our non-core assets in the Powder River Basin in exchange for an option payment of $30 million. As of this date, we reclassified the property, plant, and equipment related to these assets, in the amount of $255.5 million, as current assets held for sale on our Unaudited Consolidated Balance Sheet as of September 30, 2018 (Note 18).

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, 2017

ARO liability balance, December 31, 2017	$198,187
Accretion expense	7,437
Changes in estimate	18,913
Settlements	(9,481)
ARO liability balance, September 30, 2018	$215,056

Of the ARO balances disclosed above, $36.0 million and $20.9 million is included as current in "Accrued liabilities" on our Unaudited Condensed Consolidated Balance Sheet as of September 30, 2018 and December 31, 2017, respectively. The remainder of the ARO liability as of September 30, 2018 and December 31, 2017 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	2018	$2,459
	2019	$9,057
	2020	$8,710
	2021	$9,302
	2022	$9,935

Certain of our unconsolidated affiliates have AROs recorded at September 30, 2018 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our Consolidated Financial Statements.

7. Equity Investees

We account for our ownership in our joint ventures under the equity method of accounting. The price we pay to acquire an ownership interest in a company may exceed 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, 2018 and December 31, 2017, the unamortized excess cost amounts totaled $370.2 million and $382.4 million, respectively. We amortize the excess cost as a reduction in equity earnings in a manner similar to depreciation.

The following table presents information included in our Unaudited Condensed Consolidated Financial Statements related to our equity investees.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Genesis’ share of operating earnings	$13,364	$16,986	$40,144	$46,631
Amortization of excess purchase price	$(3,872)	(3,942)	(11,756)	(11,826)
Net equity in earnings	$9,492	$13,044	$28,388	$34,805
Distributions received	$17,044	$20,180	$55,034	$60,371

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, 2018	December 31, 2017
BALANCE SHEET DATA:		
Assets		
Current assets	$ 15,895	$ 18,711
Fixed assets, net	205,785	217,343
Other assets	966	1,203
Total assets	$ 222,646	$ 237,257
Liabilities and equity		
Current liabilities	$ 17,644	$ 17,560
Other liabilities	243,608	237,434
Equity	(38,606)	(17,737)
Total liabilities and equity	$ 222,646	$ 237,257

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
INCOME STATEMENT DATA:				
Revenues	$27,768	$30,597	$83,962	$88,003
Operating income	$17,772	$22,334	$57,444	$63,159
Net income	$15,721	$20,739	$51,731	$58,754

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.

8. Intangible Assets

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

	September 30, 2018			December 31, 2017		
	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Sodium minerals and sulfur services:						
Customer relationships	$94,654	$ 94,114	$540	$94,654	$ 92,493	$2,161
Licensing agreements	38,678	38,141	537	38,678	36,528	2,150
Non-compete agreement	800	289	511	800	89	711
Segment total	134,132	132,544	1,588	134,132	129,110	5,022
Onshore Facilities & Transportation:						
Customer relationships	35,430	35,113	317	35,430	35,082	348

Intangibles associated with lease	13,260	5,288	7,972	13,260	4,933	8,327
Segment total	48,690	40,401	8,289	48,690	40,015	8,675
Marine contract intangibles	27,000	15,750	11,250	27,000	11,700	15,300
Offshore pipeline contract intangibles	158,101	26,350	131,751	158,101	20,109	137,992
Other	31,149	15,736	15,413	28,900	13,483	15,417
Total	$399,072	$ 230,781	$168,291	$396,823	$ 214,417	$182,406

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Amortization of intangible assets	$5,475	$5,879	$16,369	$17,623

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

Remainder of	2018	$5,503
	2019	$17,679
	2020	$16,665
	2021	$10,867
	2022	$10,708

9. Debt

Our obligations under debt arrangements consisted of the following:

	September 30, 2018			December 31, 2017		
	Principal	Unamortized Discount and Debt Issuance Costs [1]	Net Value	Principal	Unamortized Discount and Debt Issuance Costs [1]	Net Value
Senior secured credit facility	$1,220,700	$ —	$1,220,700	$1,099,200	$ —	$1,099,200
5.750% senior unsecured notes due February 2021	—	—	—	145,170	1,303	143,867
6.750% senior unsecured notes due August 2022	750,000	13,601	736,399	750,000	16,077	733,923
6.000% senior unsecured notes due May 2023	400,000	4,891	395,109	400,000	5,691	394,309
5.625% senior unsecured notes due June 2024	350,000	5,044	344,956	350,000	5,717	344,283
6.500% senior unsecured notes due October 2025	550,000	8,546	541,454	550,000	9,462	540,538
6.250% senior unsecured notes due May 2026	450,000	7,432	442,568	450,000	8,002	441,998
Total long-term debt	$3,720,700	$ 39,514	$3,681,186	$3,744,370	$ 46,252	$3,698,118

(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 $11.6 million and $14.1 million as of September 30, 2018 and December 31, 2017, respectively.

As of September 30, 2018, we were in compliance with the financial covenants contained in our credit agreement and senior unsecured notes indentures.

Senior Secured Credit Facility

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, 2018, we had $1.2 billion borrowed under our $1.7 billion credit facility, with $30.1 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 $1.2 million was outstanding at September 30, 2018. 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, 2018 was $478.1 million.

Senior Unsecured Note Issuances, Redemption, and Extinguishment

On December 11, 2017, we issued $450 million in aggregate principal amount of 6.25% senior unsecured notes due May 15, 2026 (the "2026 Notes"). Interest payments are due May 15 and November 15 of each year with the initial interest payment due May 15, 2018. Our 2026 Notes mature on May 15, 2026. That issuance generated proceeds of $441.8 million, net of issuance costs incurred. We used $204.8 million of the net proceeds to redeem the portion of the 5.75% senior unsecured notes due February 15, 2021 (the "2021 Notes") that were validly tendered and the remaining net proceeds to repay a portion of the borrowings outstanding under our revolving credit facility. On February 15, 2018, we redeemed our remaining 2021 Notes in full at a redemption price of 101.438% of the principal amount, plus accrued and unpaid interest up to, but not including, the redemption date. We incurred a total loss of approximately $3.3 million relating to the extinguishment of those notes (including the write-off of the related unamortized debt issuance costs), which is recorded as "Other income (expense)" in our Consolidated Statements of Operations for the nine months ended September 30, 2018.

10. Partners’ Capital, Mezzanine Capital and Distributions

At September 30, 2018, our outstanding common units consisted of 122,539,221 Class A units and 39,997 Class B units.

Distributions

We paid or will pay the following distributions to our common unitholders in 2017 and 2018:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2017			
1st Quarter	May 15, 2017	$0.7200	$88,257
2nd Quarter	August 14, 2017	$0.7225	$88,563
3rd Quarter	November 14, 2017	$0.5000	$61,290
4th Quarter	February 14, 2018	$0.5100	$62,515
2018			
1st Quarter	May 15, 2018	$0.5200	$63,741
2nd Quarter	August 14, 2018	$0.5300	$64,967
3rd Quarter	November 14, 2018 (1)	$0.5400	$66,193

(1) This distribution was declared on October 9, 2018 and will be paid to unitholders of record as of October 31, 2018.

Class A Convertible Preferred Units

On September 1, 2017, we sold $750 million of our 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.

Accounting for the Class A Convertible Preferred Units

Our preferred units are considered redeemable securities under GAAP due to the existence of redemption provisions upon a deemed liquidation event that is outside our control. Therefore, we present them as temporary equity in the mezzanine section of the Consolidated Balance Sheet. Because our preferred units are not currently redeemable and we do not have plans or expect any events that constitute a change of control in our partnership agreement, we present our preferred units at their initial carrying amount. However, we would be required to adjust that carrying amount if it becomes probable that we would be required to redeem our preferred units.

Initial and Subsequent Measurement

We initially recognized our preferred units at their issuance date fair value, net of issuance costs. We will not be required to adjust the carrying amount of our preferred units until it becomes probable that they would become redeemable.

Once redemption becomes probable, we would adjust the carrying amount of our preferred units to the redemption value over a period of time comprising the date the feature first becomes probable and the date the units can first be redeemed.

Preferred unit distributions are recognized on the date in which they are declared. In January 2018, we declared a $16.5 million distribution on our preferred units owned as of January 31, 2018. This distribution was paid in kind ("PIK") through the issuance of 490,252 additional preferred units. In April 2018, we declared a $16.9 million distribution on our preferred units owned of record as of May 1, 2018. This distribution was PIK through the issuance of 500,976 additional preferred units. In July 2018, we declared a $17.3 million distribution on our preferred units owned of record as of July 31, 2018. This distribution was PIK through the issuance of 511,934 additional preferred units.The following tables show the change in our mezzanine and preferred units balances from December 31, 2017 to September 30, 2018:

Mezzanine Capital Balance	As of September 30, 2018
Balance as of December 31, 2017	$697,151
Distributions paid-in-kind	50,671
Allocation of Distributions paid in-kind to Preferred Distribution Rate Reset Election (Note 16)	(3,095)
Balance as of September 30, 2018	$744,727

Number of Class A Convertible Preferred Units	Nine months ended September 30, 2018
Balance as of December 31, 2017	22,411,728
Distributions paid-in-kind	1,503,162
Balance as of September 30, 2018	23,914,890

Net income (loss) attributable to common unitholders is reduced by preferred unit distributions that accumulated during the period. During 2018, net income (loss) attributable to common unitholders was reduced by $51.8 million as a result of distributions that accumulated during the period. With respect to our preferred units to be issued relating to the third quarter of 2018, we elected to make a PIK payment for the quarterly distribution, which will result in the issuance of an additional 523,132 preferred units. This PIK amount equates to a distribution of $0.7374 per preferred unit for the quarter, or $2.9496 annualized. These distributions will be paid on November 14, 2018 to unitholders holders of record at the close of business October 31, 2018.

11. Net Income (Loss) Per Common Unit

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

The dilutive effect of our preferred units is calculated using the if-converted method. Under the if-converted method, our 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, 2018, the effect of the assumed conversion of the 23,914,890 preferred units was anti-dilutive and was not included in the computation of diluted earnings per unit.

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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,	
	2018	2017	2018	2017
Net Income (Loss) Attributable to Genesis Energy L.P.	$(323)	6,312	$18,708	$67,135
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(17,635)	(5,469)	(51,780)	(5,469)
Net Income (Loss) Available to Common Unitholders	$(17,958)	$843	$(33,072)	$61,666
Weighted Average Outstanding Units	122,579	122,579	122,579	121,198
Basic and Diluted Net Income (Loss) per Common Unit	$(0.15)	$0.01	$(0.27)	$0.51

12. Business Segment Information

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

- Offshore pipeline transportation – offshore transportation 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 for refineries 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 ;and
- Marine transportation – marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America.

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 long-term incentive compensation 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	Onshore Facilities & Transportation	Marine Transportation	Total
Three Months Ended September 30, 2018					
Segment margin (a)	$ 70,963	$63,942	$ 36,189	$ 12,113	$183,207
Capital expenditures (b)	$ 564	$20,819	$ 16,700	$ 4,936	$43,019
Revenues:					
External customers	$ 70,115	$293,491	$ 327,844	$ 53,828	$745,278
Intersegment (c)	—	(1,769)	(699)	2,468	—
Total revenues of reportable segments	$ 70,115	$291,722	$ 327,145	$ 56,296	$745,278
Three Months Ended September 30, 2017					
Segment margin (a)	$ 78,228	$30,031	$ 25,606	$ 12,649	$146,514
Capital expenditures (b)	$ 2,356	$1,330,947	$ 26,578	$ 23,831	$1,383,712
Revenues:					
External customers	$ 80,671	$111,756	$ 247,603	$ 46,084	$486,114
Intersegment (c)	—	(1,991)	(459)	2,450	—
Total revenues of reportable segments	$ 80,671	$109,765	$ 247,144	$ 48,534	$486,114
Nine Months Ended September 30, 2018					
Segment Margin (a)	$ 215,738	$192,875	$ 83,622	$ 35,066	$527,301
Capital expenditures (b)	$ 2,665	$49,078	$ 52,559	$ 25,615	$129,917
Revenues:					
External customers	$ 213,344	$881,822	$ 976,193	$ 152,115	2,223,474
Intersegment (c)	—	(5,309)	(3,986)	9,295	—
Total revenues of reportable segments	$ 213,344	$876,513	$ 972,207	$ 161,410	$2,223,474
Nine Months Ended September 30, 2017					
Segment Margin (a)	$ 243,528	$63,864	$ 71,999	$ 39,768	$419,159
Capital expenditures (b)	$ 8,498	$1,331,892	$ 115,663	$ 44,496	$1,500,549
Revenues:					
External customers	$ 244,653	$204,237	$ 715,839	$ 143,599	1,308,328
Intersegment (c)	(1,216)	(6,358)	(865)	8,439	—
Total revenues of reportable segments	$ 243,437	$197,879	$ 714,974	$ 152,038	$1,308,328

Total assets by reportable segment were as follows:

	September 30, 2018	December 31, 2017
Offshore pipeline transportation	$ 2,417,602	$ 2,486,803
Sodium minerals and sulfur services	1,839,107	1,848,188
Onshore facilities and transportation	1,824,199	1,927,976
Marine transportation	813,293	824,777
Other assets	40,967	49,737
Total consolidated assets	$ 6,935,168	$ 7,137,481

(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,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Total Segment Margin	$183,207	$146,514	$527,301	$419,159
Corporate general and administrative expenses	(23,760)	(18,230)	(47,686)	(33,694)
Depreciation, depletion, amortization and accretion	(94,522)	(66,436)	(252,392)	(184,213)
Interest expense	(58,819)	(47,388)	(172,864)	(122,117)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income (1)	(7,552)	(7,136)	(26,646)	(25,566)
Other non-cash items	(999)	(4,788)	(7,774)	(6,218)
Cash payments from direct financing leases in excess of earnings	(1,931)	(1,751)	(5,654)	(5,127)
Loss on extinguishment of debt	—	—	(3,339)	—
Differences in timing of cash receipts for certain contractual arrangements (2)	792	5,847	5,271	11,694
Gain on sale of assets	3,363	—	3,363	26,684
Non-cash provision for leased items no longer in use	181	—	42	(12,589)
Income tax expense	(283)	(320)	(914)	(878)
Net income (loss) attributable to Genesis Energy, L.P.	$(323)	$6,312	$18,708	$67,135

(1) Includes distributions attributable to the quarter and received during or promptly following such quarter.
(2) Includes the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts.

13. Transactions with Related Parties

The transactions with related parties were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues:				
Sales of CO_2 to Sandhill Group, LLC (1)	$—	$ 750	$1,233	$2,153
Revenues from services and fees to Poseidon Oil Pipeline Company, LLC (2)	3,021	3,170	9,260	9,236
Revenues from product sales to ANSAC	90,433	31,774	275,167	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)	247	254	746	744
Charges for services from ANSAC	1,393	454	4,427	454

(1) We owned a 50% interest in Sandhill Group, LLC which was sold during the three months ended September 30, 2018.
(2) We own 64% interest in Poseidon Oil Pipeline Company, LLC.

Our CEO, Mr. Sims, owns an aircraft which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. Based on current market rates for chartering of private aircraft under long-term, priority arrangements with industry recognized chartering companies, we believe that the terms of this arrangement are no worse than what we could have expected to obtain in an arms-length transaction.

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Poseidon
At September 30, 2018 and December 31, 2017 Poseidon Oil Pipeline Company, LLC owed us $2.0 million and $2.2 million, respectively, for services rendered.
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, 2018 reflect $2.2 million and $6.5 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 using a pro rata calculation based on sales. Those costs include sales and marketing, employees, office supplies, professional fees, 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 our 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 $90.4 million and $275.2 million, respectively during the three and nine months ended September 30, 2018. The costs charged to us by ANSAC, included in operating costs, were $1.4 million and $4.4 million, respectively during the three and nine months ended September 30, 2018.
Receivables from and payables to ANSAC as of September 30, 2018 and December 31, 2017 are as follows:

	September 30, 2018	December 31, 2017
Receivables:		
ANSAC	$ 63,431	$ 74,490
Payables:		
ANSAC	$ 1,366	$ 1,223

ANSAC is considered a variable interest entity (VIE) because we experience certain risks and rewards from our relationship with it. Because we do not exercise control over ANSAC and are not considered its primary beneficiary, we do not consolidate ANSAC.

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14. 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,	
	2018	2017
(Increase) decrease in:		
Accounts receivable	$87,318	$(79,938)
Inventories	9,159	31,973
Deferred charges	(4,899)	(293)
Other current assets	(1,798)	(2,769)
(Decrease) increase in:		
Accounts payable	(68,974)	32,896
Accrued liabilities	6,524	(8,131)
Net changes in components of operating assets and liabilities	$27,330	$(26,262)

Payments of interest and commitment fees were $158.2 million and $126.9 million for the nine months ended September 30, 2018 and September 30, 2017, respectively. We capitalized interest of $2.7 million and $13.8 million during the nine months ended September 30, 2018 and September 30, 2017.
At September 30, 2018 and September 30, 2017, we had incurred liabilities for fixed and intangible asset additions totaling $16.6 million and $25.7 million, respectively, that had not been paid at the end of the quarter, and, therefore, were not included in the caption "Payments to acquire fixed and intangible assets" under Cash Flows from Investing Activities in the Unaudited Condensed Consolidated Statements of Cash Flows.
On August 7, 2018, we granted a third party a time-limited option to acquire certain of our non-core assets in the Powder River Basin in exchange for an option payment of $30 million. We have reflected our proceeds from this option payment in the net cash flows from investing activities section of the Unaudited Condensed Consolidated Statements of Cash Flows. Additionally, we reclassified the property, plant, and equipment related to these assets, in the amount of $255.5 million, as current assets held for sale on our Unaudited Consolidated Balance Sheet as of September 30, 2018.

15. 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.

Additionally, in 2018 we have entered into swap arrangements. Our Alkali Business relies on natural gas to generate heat and electricity for operations. We use a combination of commodity price swap contracts and future purchase contracts to manage our exposure to fluctuations in natural gas prices. The swap contracts fix the basis differential between NYMEX Henry Hub and NW Rocky Mountain posted prices. We do not designate these contracts as hedges for accounting purposes. We recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales.

At September 30, 2018, we had the following outstanding derivative commodity contracts that were entered into to economically hedge inventory or fixed price purchase commitments.

	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	50	—
Weighted average contract price per bbl	$ 69.14	$ —
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	315	221
Weighted average contract price per bbl	$ 68.70	$ 68.15
Natural gas swaps:		
Contract volumes (10,000 MMBTU)	502	—
Weighted average price differential per MMBTU	$ 0.65	$ —
Natural gas futures:		
Contract volumes (10,000 MMBTU)	54	507
Weighted average contract price per MMBTU	$ 3.01	$ 2.82
Diesel futures:		
Contract volumes (1,000 bbls)	15	5
Weighted average contract price per bbl	$ 2.29	$ 2.23
NYM RBOB Gas futures:		
Contract volumes (42,000 gallons)	22	12
Weighted average contract price per gallon	$ 2.03	$ 2.00
Fuel oil futures:		
Contract volumes (1,000 bbls)	255	—
Weighted average contract price per bbl	$ 65.90	$ —
Crude oil options:		
Contract volumes (1,000 bbls)	50	10
Weighted average premium received	$ 1.34	$ 0.31

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, 2018 and December 31, 2017:
Fair Value of Derivative Assets and Liabilities

	Unaudited Condensed Consolidated Balance Sheets Location	Fair Value September 30, 2018	Fair Value December 31, 2017
Asset Derivatives:			
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$1,481	$ 505
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(1,481)	(505)
Net amount of assets presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$—	$ —
Natural Gas Swap (undesignated hedge)	Current Assets - Other	170	—
Commodity derivatives - futures and call options (designated hedges):			
Gross amount of recognized assets	Current Assets - Other	$28	$ 54
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other	(28)	(54)
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	(48,572)	(45,209)
Natural Gas Swap (undesignated hedge)	Current Liabilities - Accrued Liabilities	(28)	—
Commodity derivatives - futures and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other [1]	$(2,879)	$ (1,203)
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other [1]	2,660	1,203
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$(219)	$ —
Commodity derivatives - futures and call options (designated hedges):			
Gross amount of recognized liabilities	Current Assets - Other [1]	$(230)	$ (863)
Gross amount offset in the Unaudited Condensed Consolidated Balance Sheets	Current Assets - Other [1]	—	338
Net amount of liabilities presented in the Unaudited Condensed Consolidated Balance Sheets related to commodity derivatives		$(230)	$ (525)

(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 10 and Note 16 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, 2018, we had a net broker receivable of approximately $1.2 million (consisting of initial margin of $2.0 million decreased by $0.8 million of variation margin). As of December 31, 2017, we had a net broker receivable of approximately $1.0 million (consisting of initial margin of $1.3 million decreased by $0.3 million of variation margin). At September 30, 2018 and December 31, 2017, 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 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 110% of the Issue Price. The Rate Reset Election of our 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, 2018, the fair value of this embedded derivative was a liability of $48.6 million. See Note 10 for additional information regarding our preferred units and the Rate Reset Election.

Effect on Operating Results

		Amount of Gain (Loss) Recognized in Income			
	Unaudited Condensed Consolidated Statements of Operations Location	Three Months Ended September 30,		Nine Months Ended September 30,	
		2018	2017	2018	2017
Commodity derivatives - futures and call options:					
Contracts designated as hedges under accounting guidance	Onshore facilities and transportation product costs	$759	$(3,399)	$(2,028)	$8,433
Contracts not considered hedges under accounting guidance	Onshore facilities and transportation product costs, sodium minerals and sulfur services operating costs	(1,157)	(1,329)	(6,833)	650
Total commodity derivatives		$(398)	$(4,728)	$(8,861)	$9,083
Natural Gas Swap Liability	Sodium minerals and sulfur services operating costs	$229	$—	$44	$—
Preferred Distribution Rate Reset Election	Other income (expense)	$1,826	$(2,276)	$(268)	$(2,276)

16. 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

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(3) Level 3 fair values are based on unobservable inputs in which little or no market data exists.
As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.
Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.
The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2018 and December 31, 2017.

	Fair Value at September 30, 2018			Fair Value at December 31, 2017		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$1,509	$170	$—	$559	$—	$—
Liabilities	$(3,109)	$(28)	$—	$(2,066)	$—	$—
Preferred Distribution Rate Reset Election	$—	$—	$(48,572)	$—	$—	$(45,209)

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:

	Nine months ended September 30, 2018
Balance as of December 31, 2017	$(45,209)
Change in fair value included in earnings	(268)
Allocation of Distributions Paid-in-kind	(3,095)
Balance as of September 30, 2018	$(48,572)

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 the swaps contracts was determined using market price quotations and a pricing model. The swap contracts were considered a level 2 input in the fair value hierarchy at September 30, 2018.
The fair value of the embedded derivative feature is based on a valuation model that estimates the fair value of our 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 15 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,

2018 our senior unsecured notes had a carrying value and fair value of $2.5 billion compared to $2.6 billion and $2.7 billion, respectively, at December 31, 2017. 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.

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17. 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.

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 during that period) relating to certain leased railcars no longer in use. As of September 30, 2018, our remaining provision is $7.5 million, of which $3.4 million is recorded as current and included in accrued liabilities in our Unaudited Condensed Consolidated Balance Sheet, with the remainder included in other long-term liabilities.

18. Subsequent Events

On August 7, 2018, we granted a third party a time-limited option to acquire certain of our Powder River Basin midstream assets in exchange for an option payment of $30 million. We classified the property, plant, and equipment related to these assets, in the amount of $255.5 million, as current assets held for sale on our Unaudited Consolidated Balance Sheet as of September 30, 2018. Additionally, we had $1.1 million included in accounts receivable and $2.7 million included in current liabilities in the Unaudited Consolidated Balance Sheet as of September 30, 2018 related to these assets.

On October 11, 2018, we completed the divestiture of our Powder River Basin midstream assets and received total net proceeds of approximately $300 million inclusive of the $30 million option payment.

19. Condensed Consolidating Financial Information

Our $2.5 billion aggregate principal amount of senior unsecured notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P.’s current and future 100% owned domestic subsidiaries, except Genesis Free State Pipeline, LLC, Genesis NEJD Pipeline, LLC and certain other minor subsidiaries. Genesis NEJD Pipeline, LLC is 100% owned by Genesis Energy, L.P., the parent company. The remaining non-guarantor subsidiaries are owned by Genesis Crude Oil, L.P., a guarantor subsidiary. Genesis Energy Finance Corporation has no independent assets or operations. See Note 9 for additional information regarding our consolidated debt obligations.

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

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Unaudited Condensed Consolidating Balance Sheet
September 30, 2018

	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	$ —	$9,114	$ 2,758	$—	$11,878
Other current assets	75	—	737,367	12,152	(48)	749,546
Total current assets	81	—	746,481	14,910	(48)	761,424
Fixed assets, at cost	—	—	5,328,399	77,585	—	5,405,984
Less: Accumulated depreciation	—	—	(854,241)	(28,592)	—	(882,833)
Net fixed assets	—	—	4,474,158	48,993	—	4,523,151
Mineral Leaseholds	—	—	561,593	—	—	561,593
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	11,574	—	440,330	119,979	(164,397)	407,486
Advances to affiliates	3,626,049	—	—	97,840	(3,723,889)	—
Equity investees	—	—	356,468	—	—	356,468
Investments in subsidiaries	2,691,191	—	80,157	—	(2,771,348)	—
Total assets	$6,328,895	$ —	$6,984,233	$ 281,722	$(6,659,682)	$6,935,168
LIABILITIES AND CAPITAL						
Current liabilities	$55,001	$ —	$369,890	$ 5,352	$(237)	$430,006
Senior secured credit facility	1,220,700	—	—	—	—	1,220,700
Senior unsecured notes	2,460,486	—	—	—	—	2,460,486
Deferred tax liabilities	—	—	12,293	—	—	12,293
Advances from affiliates	—	—	3,723,793	—	(3,723,793)	—
Other liabilities	48,572	—	193,480	198,025	(164,254)	275,823
Total liabilities	3,784,759	—	4,299,456	203,377	(3,888,284)	4,399,308
Mezzanine Capital:						
Class A Convertible Preferred Units	744,727	—	—	—	—	744,727
Partners' capital, common units	1,799,409	—	2,685,381	86,017	(2,771,398)	1,799,409
Accumulated other comprehensive loss[1]	—	—	(604)	—	—	(604)
Noncontrolling interests	—	—	—	(7,672)	—	(7,672)
Total liabilities, mezzanine capital and partners' capital	$6,328,895	$ —	$6,984,233	$ 281,722	$(6,659,682)	$6,935,168

[1]The entire balance and activity within Accumulated Other Comprehensive Income is related to our pension held within our Guarantor Subsidiaries.

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

Unaudited Condensed Consolidating Balance Sheet
December 31, 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	$ —	$8,340	$ 695	$—	$9,041
Other current assets	50	—	614,682	12,316	(56)	626,992
Total current assets	56	—	623,022	13,011	(56)	636,033
Fixed assets, at cost	—	—	5,523,431	77,584	—	5,601,015
Less: Accumulated depreciation	—	—	(708,269)	(26,717)	—	(734,986)
Net fixed assets	—	—	4,815,162	50,867	—	4,866,029
Mineral Leaseholds	—	—	564,506	—	—	564,506
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	14,083	—	378,371	126,300	(154,437)	364,317
Advances to affiliates	3,808,712	—	—	85,423	(3,894,135)	—
Equity investees and other investments	—	—	381,550	—	—	381,550
Investments in subsidiaries	2,689,861	—	82,616	—	(2,772,477)	—
Total assets	$6,512,712	$ —	$7,170,273	$ 275,601	$(6,821,105)	$7,137,481
LIABILITIES AND CAPITAL						
Current liabilities	$46,086	$ —	$399,017	$ 11,417	$(256)	$456,264
Senior secured credit facilities	1,099,200	—	—	—	—	1,099,200
Senior unsecured notes	2,598,918	—	—	—	—	2,598,918
Deferred tax liabilities	—	—	11,913	—	—	11,913
Advances from affiliates	—	—	3,894,027	—	(3,894,027)	—
Other liabilities	45,210	—	182,414	183,237	(154,290)	256,571
Total liabilities	3,789,414	—	4,487,371	194,654	(4,048,573)	4,422,866
Mezzanine Capital:						
Class A Convertible Preferred Units	697,151	—	—	—	—	697,151
Partners' capital, common units	2,026,147	—	2,683,506	89,026	(2,772,532)	2,026,147
Accumulated other comprehensive loss[(1)]	—	—	(604)	—	—	(604)
Noncontrolling interests	—	—	—	(8,079)	—	(8,079)
Total liabilities, mezzanine capital and partners' capital	$6,512,712	$ —	$7,170,273	$ 275,601	$(6,821,105)	$7,137,481

[(1)]The entire balance and activity within Accumulated Other Comprehensive Income is related to our pension plan held within our Guarantor Subsidiaries.

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

Unaudited Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2018

	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	$ —	$ —	$ 70,115	$ —	$ —	$ 70,115
Sodium minerals and sulfur services	—	—	290,837	2,922	(2,037)	291,722
Marine transportation	—	—	56,296	—	—	56,296
Onshore facilities and transportation	—	—	322,275	4,870	—	327,145
Total revenues	—	—	739,523	7,792	(2,037)	745,278
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	294,969	287	—	295,256
Marine transportation costs	—	—	44,195	—	—	44,195
Sodium minerals and sulfur services operating costs	—	—	228,721	2,520	(2,037)	229,204
Offshore pipeline transportation operating costs	—	—	17,217	536	—	17,753
General and administrative	—	—	24,209	—	—	24,209
Depreciation, depletion and amortization	—	—	85,229	6,647	—	91,876
Gain on sale of assets	—	—	(3,363)	—	—	(3,363)
Total costs and expenses	—	—	691,177	9,990	(2,037)	699,130
OPERATING INCOME	—	—	48,346	(2,198)	—	46,148
Equity in earnings of subsidiaries	57,078	—	(4,047)	—	(53,031)	—
Equity in earnings of equity investees	—	—	9,492	—	—	9,492
Interest (expense) income, net	(59,229)	—	3,683	(3,273)	—	(58,819)
Other income	1,828	—	—	—	—	1,828
Income before income taxes	(323)	—	57,474	(5,471)	(53,031)	(1,351)
Income tax benefit (expense)	—	—	(383)	100	—	(283)
NET INCOME (LOSS)	(323)	—	57,091	(5,371)	(53,031)	(1,634)
Net loss attributable to noncontrolling interest	—	—	—	1,311	—	1,311
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ (323)	$ —	$ 57,091	$ (4,060)	$ (53,031)	$ (323)
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	$ (17,635)	$ —	$ —	$ —	$ —	$ (17,635)
NET INCOME (LOSS) AVAILABLE TO COMMON UNIT HOLDERS	$ (17,958)	$ —	$ 57,091	$ (4,060)	$ (53,031)	$ (17,958)

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

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 costs	—	—	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, depletion 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 (LOSS)	6,312	—	56,010	(579)	(55,583)	6,160
Net loss attributable to noncontrolling interest	—	—	—	152	—	152
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 6,312	$ —	$ 56,010	$ (427)	$ (55,583)	$ 6,312
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(5,469)	—	—	—	—	(5,469)
NET INCOME (LOSS) AVAILABLE TO COMMON UNIT HOLDERS	$ 843	$ —	$ 56,010	$ (427)	$ (55,583)	$ 843

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

Unaudited Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2018

	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	$ —	$ —	$ 213,344	$ —	$ —	$ 213,344
Sodium minerals and sulfur services	—	—	873,863	9,056	(6,406)	876,513
Marine transportation	—	—	161,410	—	—	161,410
Onshore facilities and transportation	—	—	957,618	14,589	—	972,207
Total revenues	—	—	2,206,235	23,645	(6,406)	2,223,474
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	900,638	836	—	901,474
Marine transportation costs	—	—	126,259	—	—	126,259
Sodium minerals and sulfur services operating costs	—	—	683,989	7,636	(6,406)	685,219
Offshore pipeline transportation operating costs	—	—	51,688	1,845	—	53,533
General and administrative	—	—	49,412	—	—	49,412
Depreciation, depletion and amortization	—	—	236,914	7,897	—	244,811
Gain on sale of assets	—	—	(3,363)	—	—	(3,363)
Total costs and expenses	—	—	2,045,537	18,214	(6,406)	2,057,345
OPERATING INCOME	—	—	160,698	5,431	—	166,129
Equity in earnings of subsidiaries	196,103	—	(2,518)	—	(193,585)	—
Equity in earnings of equity investees	—	—	28,388	—	—	28,388
Interest (expense) income, net	(173,791)	—	10,887	(9,960)	—	(172,864)
Other expense	(3,604)	—	—	—	—	(3,604)
Income before income taxes	18,708	—	197,455	(4,529)	(193,585)	18,049
Income tax benefit (expense)	—	—	(1,238)	324	—	(914)
NET INCOME (LOSS)	18,708	—	196,217	(4,205)	(193,585)	17,135
Net loss attributable to noncontrolling interest	—	—	—	1,573	—	1,573
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 18,708	$ —	$ 196,217	$ (2,632)	$ (193,585)	$ 18,708
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(51,780)	—	—	—	—	$ (51,780)
NET INCOME(LOSS) AVAILABLE TO COMMON UNIT HOLDERS	$ (33,072)	$ —	$ 196,217	$ (2,632)	$ (193,585)	$ (33,072)

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

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, depletion 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) benefit	—	—	(880)	2	—	(878)
NET INCOME (LOSS)	67,135	—	191,589	(1,608)	(190,438)	66,678
Net loss attributable to noncontrolling interest	—	—	—	457	—	457
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 67,135	$ —	$ 191,589	$ (1,151)	$ (190,438)	$ 67,135
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(5,469)	—	—	—	—	(5,469)
NET INCOME (LOSS) AVAILABLE TO COMMON UNIT HOLDERS	$ 61,666	$ —	$ 191,589	$ (1,151)	$ (190,438)	$ 61,666

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

Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2018

	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	$ 32,474	$ —	$ 448,273	$ 2,587	$ (175,770)	$ 307,564
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(152,868)	—	—	(152,868)
Cash distributions received from equity investees - return of investment	—	—	26,042	—	—	26,042
Investments in equity investees	—	—	(2,960)	—	—	(2,960)
Intercompany transfers	182,662	—	—	—	(182,662)	—
Repayments on loan to non-guarantor subsidiary	—	—	5,541	—	(5,541)	—
Proceeds from asset sales	—	—	36,859	—	—	36,859
Net cash used in investing activities	182,662	—	(87,386)	—	(188,203)	(92,927)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	759,800	—	—	—	—	759,800
Repayments on senior secured credit facility	(638,300)	—	—	—	—	(638,300)
Repayment of senior unsecured notes	(145,170)	—	—	—	—	(145,170)
Debt issuance costs	(242)	—	—	—	—	(242)
Intercompany transfers	—	—	(170,245)	(12,417)	182,662	—
Distributions to common unitholders	(191,224)	—	(191,224)	—	191,224	(191,224)
Contributions from noncontrolling interest	—	—	—	1,980	—	1,980
Other, net	—	—	1,356	9,913	(9,913)	1,356
Net cash used in financing activities	(215,136)	—	(360,113)	(524)	363,973	(211,800)
Net increase in cash and cash equivalents	—	—	774	2,063	—	2,837
Cash and cash equivalents at beginning of period	6	—	8,340	695	—	9,041
Cash and cash equivalents at end of period	$ 6	$ —	$ 9,114	$ 2,758	$ —	$ 11,878

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 (used in) operating activities	$ 142,721	$ —	$ 322,309	$ (8,346)	$ (250,294)	$ 206,390
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	—	—	25,917	—	—	25,917
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
Net cash used in investing activities	(1,379,098)	—	(1,443,326)	—	1,379,257	(1,443,167)
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 Class 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 provided by 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
Cash and cash equivalents at end of period	$ 6	$ —	$ 8,960	$ 728	$ —	$ 9,694

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations
The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying notes included in this Quarterly Report on Form 10-Q. The following information and such Unaudited Condensed Consolidated Financial Statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations, included in our Annual Report on Form 10-K for the year ended December 31, 2017.
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 acquisition of our trona and trona-based exploring, mining, processing, producing, marketing and selling business (our "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 our preferred units, a $550 million public offering of notes, our revolving credit facility, and cash on hand.

On August 7, 2018, we granted a third party a time-limited option to acquire our Powder River Basin midstream assets in exchange for an option payment of $30 million. On October 11, 2018, we completed the sale and received total net proceeds of approximately $300 million, inclusive of the $30 million option payment.

We reported net loss attributable to Genesis Energy, L.P. of $0.3 million during the three months ended September 30, 2018 (“2018 Quarter”) compared to net income attributable to Genesis Energy, L.P. of $6.3 million during the three months ended September 30, 2017 (“2017 Quarter”). The 2018 Quarter included three months of contribution related to our Alkali Business that we acquired on September 1, 2017, which contributed to our overall $36.7 million increase to segment margin during the 2018 Quarter relative to the 2017 Quarter. Additionally, we had a gain on sale of assets of $3.4 million and an increase in other income (expense) of approximately $4.1 million primarily due to the valuation of the embedded derivative associated with our convertible preferred units. Net income was negatively impacted in the 2018 Quarter by an increase in interest and depreciation expense, primarily driven by our acquisition of our Alkali Business, an increase in general and administrative costs during the 2018 Quarter relative to the 2017 Quarter by approximately $4.8 million, and a decrease in equity in earnings of equity investees of approximately $3.6 million.
Cash flow from operating activities was $156.7 million for the 2018 Quarter compared to $30.1 million for the 2017 Quarter. The increase in cash flows from operating activities for the 2018 Quarter was primarily driven by positive working capital effects during the period and an increase in our reported segment margin during the 2018 Quarter.
Available Cash before Reserves (as defined below in "Non-GAAP Financial Measures") was $112.7 million for the 2018 Quarter, an increase of $21.6 million, or 23.8%, from the 2017 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 $183.2 million for the 2018 Quarter, an increase of $36.7 million, or 25%, from the 2017 Quarter. A more detailed discussion of our segment results and other costs is included below in "Results of Operations".

Distribution
In October 2018, we declared our quarterly distribution to our common unitholders of $0.54 per unit related to the 2018 Quarter.

With respect to our preferred units, we have declared a PIK of the quarterly distribution, which will result in the issuance of an additional approximately 523,132 preferred units. This PIK amount equates to a distribution of $0.7374 per preferred unit for the 2018 Quarter, or $2.9496 annualized. These distributions will be payable in November 2018 to unitholders holders of record at the close of business on October 31, 2018.

Results of Operations

Revenues and Costs and Expenses

Our revenues for the 2018 Quarter increased $259.2 million, or 53%, from the 2017 Quarter. In addition, our total costs and expenses as presented on the Unaudited Statements of Operations (excluding the gain on sale of assets) increased $259.5 million, or 59%, between those two periods. These increases are primarily attributable to the effects of three months of contribution by our Alkali Business during the 2018 Quarter compared to one month of contribution during the 2017 Quarter, along with the increase in crude oil prices during the 2018 Quarter that proportionately impact our revenues and cost of sales. Excluding the effects of our Alkali Business, operating income for the 2018 Quarter would have increased by $1.1 million compared to the 2017 Quarter.

The addition of our Alkali Business resulted in a large increase in revenues and costs relative to the 2017 Quarter (which are reflected in our sodium minerals and sulfur services segment). Those increases are principally derived from mining trona ore and processing the entrained mineral sodium carbonate, also known as naturally occurring soda ash. Natural soda ash has significant cost advantages over synthetically produced soda ash. We believe that significant cost advantage will exist for the foreseeable future. Natural soda ash accounts for only about 25% of the world's production; thus, we believe we should be able to somewhat mitigate the effects of market specific factors (e.g., changes in sales prices for our products, our operating costs, and other economic considerations) on Net Income, Available Cash before Reserves, and Segment Margin in the soda ash market in which we operate.

In addition to our Alkali Business, we continue to operate in our other legacy businesses including - (i) 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; and (ii) our onshore-based refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on providing a suite of services primarily to refiners. Refiners are the shippers of approximately 80% of the volumes transported on our onshore crude pipelines, and refiners contract for over 80% 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 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. Their 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 relatively low commodity price environments. Given these facts, we do not expect changes in commodity prices to impact our Net Income, Available Cash before Reserves or Segment Margin derived from our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations 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 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 increase in our revenues and costs in this segment between the 2018 Quarter and the 2017 Quarter is primarily attributable to increases in crude oil and petroleum product prices and sales volumes as discussed further below. Nevertheless, generally 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. However, due to the indirect exposure to changes in prices discussed above, the factors addressed in our onshore facilities and transportation segment discussion above, and the fact that crude oil prices have remained low for an extended period of time as compared to the five-year period before 2015, we are reasonably hopeful that we have reached a bottom in our crude oil and petroleum product sales volumes.

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. 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."

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Prices of crude oil have increased since the 2017 Quarter. The average closing prices for West Texas Intermediate crude oil on the New York Mercantile Exchange ("NYMEX") increased 44.3% to $69.55 per barrel in the 2018 Quarter, as compared to $48.21 per barrel in the 2017 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.
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, 2018 and September 30, 2017 was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
Offshore pipeline transportation	70,963	78,228	$215,738	$243,528
Sodium minerals and sulfur services	63,942	30,031	192,875	63,864
Onshore facilities and transportation	36,189	25,606	83,622	71,999
Marine transportation	12,113	12,649	35,066	39,768
Total Segment Margin	$183,207	$146,514	$527,301	$419,159

We define Segment Margin as revenues less product costs, operating expenses, and segment general and administrative expenses, after eliminating gain or loss on sale of assets, plus or minus applicable Select Items. Although we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results. 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,	
	2018	2017	2018	2017
Total Segment Margin	$183,207	$146,514	$527,301	$419,159
Corporate general and administrative expenses	(23,760)	(18,230)	(47,686)	(33,694)
Depreciation, depletion, amortization and accretion	(94,522)	(66,436)	(252,392)	(184,213)
Interest expense	(58,819)	(47,388)	(172,864)	(122,117)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income (1)	(7,552)	(7,136)	(26,646)	(25,566)
Other non-cash items	(999)	(4,788)	(7,774)	(6,218)
Cash payments from direct financing leases in excess of earnings	(1,931)	(1,751)	(5,654)	(5,127)
Gain on sale of assets	3,363	—	3,363	26,684
Non-cash provision for leased items no longer in use	181	—	42	(12,589)
Differences in timing of cash receipts for certain contractual arrangements (2)	792	5,847	5,271	11,694
Loss on debt extinguishment	—	—	(3,339)	—
Income tax expense	(283)	(320)	(914)	(878)
Net income (loss) attributable to Genesis Energy, L.P.	$(323)	$6,312	$18,708	$67,135

(1) Includes distributions attributable to the quarter and received during or promptly following such quarter.
(2) Includes the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts.

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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,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
Offshore crude oil pipeline revenue, excluding non-cash revenues	$60,888	$67,506	$181,968	$204,585
Offshore natural gas pipeline revenue, excluding non-cash revenues	10,721	13,164	35,405	38,852
Offshore pipeline operating costs, excluding non-cash expenses	(13,828)	(15,979)	(44,631)	(46,859)
Distributions from equity investments [1]	16,781	19,535	53,870	59,100
Other	(3,599)	(5,998)	(10,874)	(12,150)
Offshore pipeline transportation Segment Margin	$70,963	$78,228	$215,738	$243,528
Volumetric Data 100% basis:				
Crude oil pipelines (average barrels/day unless otherwise noted):				
CHOPS	225,186	203,697	202,159	220,374
Poseidon	224,053	257,093	229,382	258,031
Odyssey	129,777	135,787	109,897	122,433
GOPL [2]	13,217	8,317	10,707	8,166
Total crude oil offshore pipelines	592,233	604,894	552,145	609,004
Natural gas transportation volumes (MMBtus/d)	447,460	467,095	436,023	516,974
Volumetric Data net to our ownership interest [2]:				
Crude oil pipelines (average barrels/day unless otherwise noted):				
CHOPS	225,186	203,697	202,159	220,374
Poseidon	143,394	164,540	146,804	165,140
Odyssey	37,635	39,378	31,870	35,506
GOPL [3]	13,217	8,317	10,707	8,166
Total crude oil offshore pipelines	419,432	415,932	391,540	429,186
Natural gas transportation volumes (MMBtus/d)	171,080	189,778	166,252	237,328

(1) Offshore pipeline transportation Segment Margin includes distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2018 and 2017, respectively.

(2) 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.

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

Three Months Ended September 30, 2018 Compared with Three Months Ended September 30, 2017

Offshore pipeline transportation Segment Margin for the 2018 Quarter decreased $7.3 million, or 9%, from the 2017 Quarter, primarily due to lower volumes on the Poseidon pipeline and certain associated laterals. We have continued to experience an inordinate amount of scheduled and unscheduled downtime at several of the production facilities connected to our offshore infrastructure. Notwithstanding these short term negatives, we are currently seeing increasing demand for our assets from production that is currently dedicated to 3rd party pipelines but is unable to get to shore due to a lack of capacity on such pipelines. Given our excess capacity and connectivity on certain of our systems, we expect to benefit from this takeaway capacity constraint in future periods.

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Nine Months Ended September 30, 2018 Compared with Nine Months Ended September 30, 2017

Offshore pipeline transportation Segment Margin for the first nine months of 2018 decreased $27.8 million, or 11%, from the first nine months of 2017, primarily due to lower volumes. We have continued to experience an inordinate amount of scheduled and unscheduled downtime at several of the production facilities connected to our offshore infrastructure. Additionally, during 2018, three particular major fields have underperformed our expectations. One field we believe is underperforming as a result of reservoir quality degradation and not due to mechanical factors. Offsetting this in future years are two subsea tie-backs to the same dedicated in-field production facility scheduled to come online; one in early 2019 and one later in 2019. The other two large underperforming fields we think are predominately timing related. To maximize reserve recoveries, the operator appears to be producing at a slower rate than communicated to us last year. Notwithstanding these short term negatives, we are currently seeing increasing demand for our assets from production that is currently dedicated to 3rd party pipelines but is unable to get to shore due to a lack of capacity on such pipelines. Given our excess capacity and connectivity on certain of our systems, we expect to benefit from this takeaway capacity constraint in future periods.

In addition, the minimum bill reservation fees we collect on one of our offshore oil pipelines had a prior year step down, and we collected approximately $4.4 million less in segment margin relative to the first nine months of 2017. Lastly, the first six months during 2017 included contributions of approximately $2.0 million from certain of our previously owned gas pipeline and platform assets that were sold during the second quarter of 2017.

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,	
	2018	2017	2018	2017
Volumes sold:				
NaHS volumes (Dry short tons "DST")	39,242	30,381	114,546	95,575
Soda Ash volumes (short tons sold)	886,253	336,000	2,739,253	336,000
NaOH (caustic soda) volumes (dry short tons sold)	29,357	21,746	87,190	55,962
Total	954,852	388,127	2,940,989	487,537
Revenues (in thousands):				
NaHS revenues, excluding non-cash revenues	$47,843	$33,702	$137,083	$105,209
NaOH (caustic soda) revenues	16,731	11,145	48,709	29,511
Revenues associated with Alkali Business	203,508	65,554	615,512	65,554
Other revenues	1,894	1,355	5,328	3,963
Total external segment revenues, excluding non-cash revenues	$269,976	$111,756	$806,632	$204,237
Segment Margin (in thousands)	$63,942	$30,031	$192,875	$63,864
Average index price for NaOH per DST(1)	$782	$647	$775	$613

(1) Source: IHS Chemical.

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Three Months Ended September 30, 2018 Compared with Three Months Ended September 30, 2017

Sodium minerals and sulfur services Segment Margin for the 2018 Quarter increased $33.9 million, or 113%. This increase is primarily due to the inclusion of contributions from our Alkali Business for a full quarter during 2018 relative to one month's contribution during the 2017 Quarter. The contributions thus far from our Alkali Business have exceeded our expectations and we expect continued strong performance throughout 2018 and into 2019. Costs impacting the results of our Alkali Business, many of which are similar in nature to costs related to our sulfur removal business, include costs associated with processing and producing soda ash (and other Alkali products) and marketing and selling activities. In addition, costs include activities associated with mining and extracting trona ore (including energy costs and employee compensation). Additionally, our refinery services business continues to perform well with increased NaHS volumes of 29% during the 2018 Quarter as they benefited from increased demand from certain of our international mining customers, primarily located in South America, and our domestic mining and pulp and paper customers.

Nine Months Ended September 30, 2018 Compared with Nine Months Ended September 30, 2017

Sodium minerals and sulfur services Segment Margin for the first nine months of 2018 increased $129.0 million, or 202%. This increase is principally due to the inclusion of contributions from our Alkali Business for nine months during 2018 compared to one month during 2017. The contributions from our Alkali Business have exceeded our expectations and we expect continued strong performance throughout 2018 and into 2019. Costs impacting the results of our Alkali Business, many of which are similar in nature to costs related to our legacy refinery services business, include costs associated with processing and producing soda ash (and other Alkali products) and marketing and selling activities. In addition, costs include activities associated with mining and extracting trona ore (including energy costs and employee compensation). Additionally, our refinery services business continues to perform well with increased NaHS volumes of 20% during 2018 as they benefited from increased demand from certain of our international mining customers, primarily located in South America, and our domestic mining and pulp and paper customers.

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

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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,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
Gathering, marketing, and logistics revenue	$305,296	$229,002	$912,481	$663,988
Crude oil and CO2 pipeline tariffs and revenues from direct financing leases of CO2 pipelines	20,624	17,261	55,678	48,606
Payments received under direct financing leases not included in income	1,931	1,751	5,654	5,127
Crude oil and petroleum products costs, excluding unrealized gains and losses from derivative transactions	(273,286)	(202,157)	(833,198)	(583,123)
Operating costs, excluding non-cash charges for long-term incentive compensation and other non-cash expenses	(22,068)	(21,199)	(66,743)	(64,799)
Other	3,692	948	9,750	2,200
Segment Margin	$36,189	$25,606	$83,622	$71,999
Volumetric Data (average barrels per day):				
Onshore crude oil pipelines:				
Texas	33,948	45,329	28,055	28,418
Jay	13,548	13,716	14,475	14,480
Mississippi	5,603	8,104	6,520	8,478
Louisiana (1)	150,322	130,862	139,234	115,436
Wyoming	38,391	22,204	33,957	19,816
Onshore crude oil pipelines total	241,812	220,215	222,241	186,628
CO_2 pipeline (average Mcf/day):				
Free State	104,628	68,363	101,764	73,042
Crude oil and petroleum products sales (average barrels per day):				
Total crude oil and petroleum products sales	44,288	52,082	48,618	49,255
Rail load/unload volumes (2)	83,557	42,221	63,194	55,010

(1) Total daily volume for the three and nine months ended September 30, 2018 includes 60,896 and 57,022 barrels per day, respectively, of intermediate refined products associated with our Port of Baton Rouge Terminal pipelines. Total daily volume for the three 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.
(2) Indicates total barrels for either loading or unloading at all rail facilities.

Three Months Ended September 30, 2018 Compared with Three Months Ended September 30, 2017

Onshore facilities and transportation Segment Margin for the 2018 Quarter increased $10.6 million, or 41%. This increase in the 2018 Quarter is primarily driven by increased volumes flowing through our infrastructure in the Baton Rouge corridor in Louisiana. These increased volumes are the realization of the anticipated growth within our existing commercial arrangements. Fortunately, while volumes were down on our Texas system in the 2018 Quarter relative to the 2017 Quarter due to integrity work being completed on a downstream pipeline, we were able to recognize three months of minimum volume commitments in segment margin during the 2018 Quarter. We believe the market fundamentals are intact to see increasing volumes and margin contributions both in Louisiana as well as in Texas over the next several quarters to levels sustainable for certainly the next several years.

Even after reflecting the sale of our Powder River Basin midstream assets, we would expect margin contribution from our onshore facilities and transportation segment to increase sequentially in the fourth quarter. This comes from actually moving increased volumes of crude oil rather than marketing or merchant fees which (for context) contributed less than $1 million for the third quarter.

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Nine Months Ended September 30, 2018 Compared with Nine Months Ended September 30, 2017

Segment Margin for our onshore facilities and transportation segment increased by $11.6 million, or 16%, between the first nine months of 2018 and the first nine months of 2017. The first nine months of 2018 include the effects of the third quarter increase in volumes flowing through our infrastructure in the Baton Rouge corridor in Louisiana that we completed in the fourth quarter of 2016. Fortunately, while volumes were relatively constant period over period on our re-purposed Texas system (which became operational during the second quarter of 2017), we were able to recognize nine months of minimum volume commitments in segment margin during the 2018 period compared to 5 months during the 2017 period. We believe the market fundamentals are intact to see increasing volumes and margin contributions both in Louisiana as well as in Texas over the next several quarters to levels sustainable for certainly the next several years.

Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 91 barges (82 inland and 9 offshore) with a combined transportation capacity of 3.2 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,	
	2018	2017	2018	2017
Revenues (in thousands):				
Inland freight revenues	$24,353	$19,666	$68,470	$61,725
Offshore freight revenues	17,989	17,468	52,049	54,912
Other rebill revenues [(1)]	13,954	11,400	40,891	35,401
Total segment revenues	$56,296	$48,534	$161,410	$152,038
Operating costs, excluding non-cash charges for long-term incentive compensation and other non-cash expenses	$44,183	$35,885	$126,344	$112,270
Segment Margin (in thousands)	$12,113	$12,649	$35,066	$39,768
Fleet Utilization: [(2)]				
Inland Barge Utilization	98.6 %	90.8 %	94.7 %	90.5 %
Offshore Barge Utilization	90.9 %	99.3 %	92.5 %	98.4 %

(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.

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Three Months Ended September 30, 2018 Compared with Three Months Ended September 30, 2017

Marine transportation Segment Margin for the 2018 Quarter decreased $0.5 million, or 4%, from the 2017 Quarter. This decrease in Segment Margin is primarily attributable to our offshore barge fleet entering into short-term spot price contracts, which can lead to a less favorable rebill structure and higher operating costs, as our last legacy long term contract rolled off during the first quarter of 2018. Additionally, we had an increase in operating costs during the 2018 Quarter relative to the 2017 Quarter due to an increase in dry-docking costs. We have continued to enter into short term contracts (less than a year) in both the inland and offshore markets because we believe the day rates currently being offered by the market are at, or approaching, cyclical lows. These decreases were partially offset by increased segment margin in the 2018 Quarter related to the M/T American Phoenix. During the 2017 Quarter, the M/T American Phoenix underwent its planned regulatory dry-docking inspections for approximately one month which negatively impacted segment margin. The 2018 Quarter also had higher utilization on our inland barge operation during the 2018 Quarter. We are reasonably hopeful that we've reached a bottom for the quarterly segment margin from our entire fleet of assets, but we have no expectation of the fundamentals for marine transportation showing any significant improvement through at least the next several years.

Nine Months Ended September 30, 2018 Compared with Nine Months Ended September 30, 2017

Marine transportation Segment Margin for the first nine months of 2018 decreased $4.7 million, or 12%, from the first nine months of 2017. The decrease in Segment Margin is primarily attributable to our offshore barge fleet entering into short-term spot price contracts, which can lead to a less favorable rebill structure and higher operating costs, as our last legacy term contract rolled off during the first quarter of 2018. Additionally, we had an increase in operating costs during the first nine months of 2018 relative to the first nine months of 2017 due to the increase in our dry-docking costs. We have continued to enter into short term contracts (less than a year) in both the inland and offshore markets because we believe the day rates currently being offered by the market are at, or approaching, cyclical lows. While we are reasonably hopeful that we've reached a bottom for the quarterly segment margin from our entire fleet of assets, we have no expectation of the fundamentals for marine transportation showing any significant improvement through at least the next several years. This excludes the M/T American Phoenix which is under long term contract through September 2020. These decreases were partially offset by increased segment margin in the 2018 period related to the M/T American Phoenix. During 2017, the M/T American Phoenix underwent its planned regulatory dry-docking inspections for approximately one month which negatively impacted segment margin. Additionally, the 2018 period also had higher utilization on our inland barge operation.

Other Costs, Interest, and Income Taxes

General and administrative expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below:				
Corporate	$20,624	$7,456	$37,910	$24,735
Segment	482	3,233	2,198	4,809
Long-term incentive compensation expense	1,553	(1,875)	3,171	(2,330)
Third party costs related to business development activities and growth projects	1,550	10,595	6,133	11,509
Total general and administrative expenses	$24,209	$19,409	$49,412	$38,723

Total general and administrative expenses increased $4.8 million and $10.7 million between the three and nine month periods. This increase is primarily attributable to certain dispute costs and the effects of changes in assumptions used to value our long term incentive compensation awards during 2018. These increases were offset by lower third party transaction costs associated with our acquisition and integration of our Alkali Business during 2018 relative to 2017.

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Depreciation, depletion, and amortization expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
Depreciation and depletion expense	$86,004	$57,498	$227,459	$157,819
Amortization of intangible assets	5,475	5,879	16,369	17,623
Amortization of CO2 volumetric production payments	397	355	983	1,011
Total depreciation, depletion and amortization expense	$91,876	$63,732	$244,811	$176,453

Total depreciation, depletion, and amortization expense increased $28.1 million and $68.4 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 our Alkali Business on September 1, 2017.

Interest expense, net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$17,259	$13,150	$47,700	$37,307
Interest expense, senior unsecured notes	39,547	33,276	119,628	90,495
Amortization of debt issuance costs and discount	2,669	2,894	8,238	8,154
Capitalized interest	(656)	(1,932)	(2,702)	(13,839)
Net interest expense	$58,819	$47,388	$172,864	$122,117

Net interest expense increased $11.4 million and $50.7 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 our Alkali Business in 2017, along with an increase in libor rates relative to the prior period which is a major component in the interest expense derived on our senior secured credit facility. In addition, capitalized interest decreased as a result of certain of our large organic growth projects being completed and placed into service prior to September 30, 2018.

Income tax expense

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

Liquidity and Capital Resources

General

As of September 30, 2018, we had $478.1 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.

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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 part of our strategic reallocation of capital, we continue to 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, 2018, our long-term debt totaled approximately $3.7 billion, consisting of $1.2 billion outstanding under our credit facility (including $30 million borrowed under the inventory sublimit tranche) and $2.5 billion of senior unsecured notes, comprising $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, $550 million carrying amount due October 2025, and $450 million carrying amount due May 2026.

Subsequent Events

On October 11, 2018, we completed the sale of our Powder River Basin midstream assets, for which we received total net proceeds of approximately $300 million. We applied those net proceeds to reduce the balance outstanding under our revolving credit facility.

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, 2018, we had issued no units under this program.

We have another universal shelf registration statement (our "2018 Shelf") on file with the SEC. Our 2018 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 2018 Shelf will expire in April 2021. We expect to file a replacement universal shelf registration statement before our 2018 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

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the carrying amount of inventory and the timing of payment of accounts payable and accrued liabilities related to capital expenditures.

In our back-to-back crude oil onshore facilities and transportation activities, we typically sell our purchased crude oil in the same month in which we acquire 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 onshore facilities and transportation activities, we purchase 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 14 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, 2018 and September 30, 2017.

Net cash flows provided by our operating activities for the nine months ended September 30, 2018 were $307.6 million compared to $206.4 million for the nine months ended September 30, 2017. This increase in operating cash flow is primarily due to a decrease in working capital effects and an increase in overall segment margin between the nine month periods.

Capital Expenditures, Distributions and Certain Cash Requirements

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. We currently plan to allocate a substantial portion of our excess cash flow to reduce the balance outstanding under our revolving credit facility.

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Capital Expenditures

A summary of our expenditures for fixed assets, business and other asset acquisitions for the nine months ended September 30, 2018 and September 30, 2017 is as follows:

	Nine Months Ended September 30,	
	2018	2017
	(in thousands)	
Capital expenditures for fixed and intangible assets:		
Maintenance capital expenditures:		
Offshore pipeline transportation assets	$2,188	$4,093
Sodium minerals and sulfur services assets	36,109	1,616
Marine transportation assets	13,107	17,439
Onshore facilities and transportation assets	2,562	3,213
Information technology systems	64	53
Total maintenance capital expenditures	54,030	26,414
Growth capital expenditures:		
Offshore pipeline transportation assets	477	4,405
Sodium minerals and sulfur services assets	12,968	5,276
Marine transportation assets	12,508	27,057
Onshore facilities and transportation assets	47,196	112,450
Information technology systems	2,747	114
Total growth capital expenditures	75,896	149,302
Total capital expenditures for fixed and intangible assets	129,926	175,716
Capital expenditures for acquisitions, inclusive of working capital acquired:		
Acquisition of Alkali business	—	1,325,000
Total business combinations capital expenditures	—	1,325,000
Capital expenditures related to equity investees	2,802	—
Total capital expenditures	$132,728	$1,500,716

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 do not anticipate spending material growth capital expenditures on any individual projects during the remainder of 2018.

Maintenance Capital Expenditures

Our increase in maintenance capital expenditures for the 2018 Quarter as compared to the 2017 Quarter principally relates to our Alkali Business. See further discussion under "Available Cash before Reserves" for how such maintenance capital utilization is reflected in our calculation of Available Cash before Reserves.

Distributions to Unitholders

On November 14, 2018, we will pay a distribution of $0.54 per common unit totaling $66 million with respect to the 2018 Quarter. Information on our recent distribution history is included in Note 10 to our Unaudited Condensed Consolidated Financial Statements.

With respect to our preferred units, we have declared a PIK of the quarterly distribution, which will result in the issuance of an additional approximately 523,132 preferred units. This PIK amount equates to a distribution of $0.7374 per preferred unit for the 2018 Quarter, or $2.9496 annualized. These distributions will be payable on November 14, 2018 to unitholders holders of record at the close of business on October 31, 2018.

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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,	
	2018	2017
	(in thousands)	
Net income (loss) attributable to Genesis Energy, L.P.	$(323)	$6,312
Income Tax Expense	283	320
Depreciation, depletion, amortization and accretion	94,522	66,436
Plus (minus) Select Items, net	23,634	19,654
Maintenance capital utilized [1]	(5,200)	(3,375)
Cash tax expense	(234)	(170)
Other	1	1,860
Available Cash before Reserves	112,683	91,037

(1) For a description of the term "maintenance capital utilized", please see the definition of the term "Available Cash before Reserves" discussed below. Maintenance capital expenditures in the 2018 Quarter and 2017 Quarter were $21.9 million and $10.9 million, respectively. This increase principally is a result of expenditures associated with our Alkali Business.

We define Available Cash before Reserves ("Available Cash before Reserves") as net income before interest, taxes, depreciation and amortization (including impairment, write-offs, accretion and similar items) after eliminating other non-cash revenues, expenses, gains, losses and charges (including any loss on asset dispositions), plus or minus certain other select items that we view as not indicative of our core operating results (collectively, "Select Items"), as adjusted for certain items, the most significant of which in the relevant reporting periods have been the sum of maintenance capital utilized, net interest expense and cash tax expense. Although, we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results. The most significant Select Items in the relevant reporting periods are set forth below.

	Three Months Ended September 30,	
	2018	2017
	(in thousands)	
I. Applicable to all Non-GAAP Measures		
Differences in timing of cash receipts for certain contractual arrangements[1]	(792)	(5,847)
Adjustment regarding direct financing leases[2]	1,931	1,751
Certain non-cash items:		
Unrealized loss on derivative transactions excluding fair value hedges, net of changes in inventory value	(1,989)	2,168
Adjustment regarding equity investees[3]	7,552	7,136
Other	2,948	3,046
Sub-total Select Items, net[4]	9,650	8,254
II. Applicable only to Available Cash before Reserves		

Certain transaction costs[5]	1,550	10,595
Equity compensation adjustments	39	(501)
Other[6]	12,395	1,306
Total Select Items, net[7]	23,634	19,654

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(1) Includes the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts. For purposes of our Non-GAAP measures, we add those amounts in the period of payment and deduct them in the period in which GAAP recognizes them.
(2) Represents the net effect of adding cash receipts from direct financing leases and deducting expenses relating to direct financing leases.
(3) Represents the net effect of adding distributions from equity investees and deducting earnings of equity investees net to us.
(4) Represents all Select Items applicable to Segment Margin and Available Cash before Reserves
(5) Represents transaction costs relating to certain merger, acquisition, transition, and financing transactions incurred in advance of acquisition.
(6) Includes general and administrative costs associated with certain dispute costs.
(7) Represents Select Items applicable to Available Cash before Reserves.

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 12 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.
In the fourth quarter of 2017, we revised portions of the format and definitions relating to our presentation of non-GAAP financial measures. Amounts attributable to prior periods have been recast.
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, after eliminating gain or loss on sale of assets, plus or minus applicable Select Items. Although, we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results.

A reconciliation of total Segment Margin to net income is included in our segment disclosure in Note 12 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, often referred to by others 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;

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(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.

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

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

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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, 2017.

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, 2017, 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, estimated or projected future financial performance, 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," "positio "strategy," "should" or "will," or the negative of those 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, soda ash, caustic soda and CO2, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;
- throughput levels and rates;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and close strategic acquisitions on acceptable terms (including obtaining third-party consents and waivers of preferential rights), develop or construct 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, individual plants, or other businesses for which we transport crude oil, petroleum, natural gas or other products or to whom we sell soda ash, petroleum, or other 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 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, 2017. 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, 2017. There have been no material changes that would affect the quantitative and qualitative disclosures provided therein. Also, see Note 15 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 2018 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, 2017. 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, 2017.

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017, 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 2018 Quarter.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

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

Item 5. Other Information

None.

Item 6. Exhibits.

(a) Exhibits

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	Second Amendment to Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P., dated December 31, 2017 (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K dated January 4, 2018, File No. 001-12295).
3.6	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)
3.7	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).

3.8	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).
3.9	Certificate of Incorporation of Genesis Energy Finance Corporation, dated as of November 26, 2006 (incorporated by reference to Exhibit 3.7 to Registration Statement on Form S-4 filed on September 26, 2011, File No. 333-177012).
3.10	Bylaws of Genesis Energy Finance Corporation (incorporated by reference to Exhibit 3.8 to Registration Statement on Form S-4 filed on September 26, 2011, File No. 333-177012).
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	Fourteenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of August 28, 2018, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
*4.3	Twelfth Supplemental Indenture for 6.000% Senior Notes due 2023, 6.75% Senior Notes due 2022, 6.50% Senior Notes due 2025, and 6.250% Senior Notes due 2026, dated as of August 28, 2018, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
10.1	Seventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of August 28, 2018, among Genesis Energy, L.P., as the borrower, Wells Fargo Bank, National Association, as administrative agent and issuing bank, Bank of America, N.A. and Bank of Montreal, as co-syndication agents, U.S. Bank National Association, as documentation agent, and the lenders and other parties party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on August 31, 2018, File No. 333-177012).
*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 1, 2018 By: /s/ ROBERT V. DEERE
Robert V. Deere
Chief Financial Officer
(Duly Authorized Officer)