Lalor Angela S
Form 4
September 02, 2011

FORM 4

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

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

OMB Number:	3235-0287
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(Print or Type Responses)

1. Name and Address of Reporting Person *
Lalor Angela S

(Last) (First) (Middle)

3M CENTER

(Street)

ST. PAUL, MN 55144-1000

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
3M CO [MMM]

3. Date of Earliest Transaction (Month/Day/Year)
09/01/2011

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
VICE PRESIDENT HR

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security	2. Conversion or Exercise	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any	4. Transaction Code	5. Number of Derivative Securities	6. Date Exercisable and Expiration Date (Month/Day/Year)	7. Title and Amount of Underlying Securities (Instr. 3 and 4)	8. I De Se

(Instr. 3)	Price of Derivative Security		(Month/Day/Year)	(Instr. 8)		Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)					(In
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Restricted Stock Units	(1)	09/01/2011		A		12,254		(2)	(2)	Common Stock	12,254

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Lalor Angela S 3M CENTER ST. PAUL, MN 55144-1000			VICE PRESIDENT HR	

Signatures

George Ann Biros, attorney-in-fact for Angela Lalor	09/02/2011
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Each restricted stock unit represents a contingent right to receive one share of 3M common stock.

(2) The restricted stock units will vest 100% three years from the grant date (9-1-2011).

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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140,513

Other comprehensive loss
—

—

—

(604
)

(604
)
Distributions to preferred unitholders
—

(5,469
)

—

—

(5,469
)
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 loss(1)
—

(6,075
)

(5,717
)

—

(11,792
)
Cash distributions to partners, net
—

(257,416
)

—

—

(257,416
)
Cash contributions from noncontrolling interests
—

—

2,592

—

2,592

Other comprehensive income
—

—

—

1,543

1,543

Distributions to preferred unitholders
—

(68,307
)

—

—

(68,307
)
December 31, 2018
122,579

$
1,690,799

$
(11,204
)

$
939

$
1,680,534

(1) Net loss includes $69.8 million attributable to preferred unitholders accumulated as of December 31, 2018.
The accompanying notes are an integral part of these consolidated financial statements.

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

	Year Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(11,792)	$ 82,079	$ 111,082
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation, depletion and amortization	313,190	252,480	222,196
Provision for leased items no longer in use	—	12,589	—
Gain on sale of assets	(42,264)	(40,311)	—
Impairment expense	126,282	—	—
Amortization and write-off of debt issuance costs and premium or discount	12,165	13,103	10,138
Amortization of unearned income and initial direct costs on direct financing leases	(13,035)	(13,747)	(14,395)
Payments received under direct financing leases	20,668	20,668	20,672
Equity in earnings of investments in equity investees	(43,626)	(51,046)	(47,944)
Cash distributions of earnings of equity investees	42,735	47,316	50,281
Non-cash effect of long-term incentive compensation plans	3,941	(5,775)	6,558
Deferred and other tax benefits	663	(4,060)	2,142
Unrealized (gains) losses on derivative transactions	(11,795)	10,943	1,287
Other, net	(4,941)	(10,839)	11,385
Net changes in components of operating assets and liabilities, net of acquisitions (See Note 16)	(2,152)	10,156	(90,650)
Net cash provided by operating activities	390,039	323,556	282,752
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(195,367)	(250,593)	(463,100)
Cash distributions received from equity investees—return of investment	28,979	35,582	36,939
Investments in equity investees	(3,018)	(4,647)	—
Acquisitions	—	(1,325,759)	(25,394)
Contributions in aid of construction costs	—	124	13,374
Proceeds from asset sales	310,099	85,722	3,609
Other, net	—	—	(151)
Net cash used in (provided by) investing activities	140,693	(1,459,571)	(434,723)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on senior secured credit facility	980,700	1,458,700	1,115,800
Repayments on senior secured credit facility	(1,109,800)	(1,637,700)	(952,600)
Proceeds from issuance of senior unsecured notes	—	1,000,000	—
Proceeds from issuance of Class A convertible preferred units, net	—	726,419	—
Repayment of senior unsecured notes	(145,170)	(204,830)	—
Debt issuance costs	(242)	(25,913)	(1,578)
Issuance of common units for cash, net	—	140,513	298,020
Contributions from noncontrolling interests	2,592	2,770	236
Distributions to common unitholders	(257,416)	(321,875)	(310,039)
Other, net	(137)	(57)	(1,734)
Net cash provided by (used in) financing activities	(529,473)	1,138,027	148,105
Net increase (decrease) in cash and cash equivalents	1,259	2,012	(3,866)
Cash and cash equivalents at beginning of period	9,041	7,029	10,895
Cash and cash equivalents at end of period	$ 10,300	$ 9,041	$ 7,029

The accompanying notes are an integral part of these consolidated financial statements.

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
1. Organization
We are a growth-oriented master limited partnership focused on the midstream segment of the crude oil and natural gas industry in the Gulf Coast region of the United States and in the Gulf of Mexico. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprise and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, Alkali Business, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks. We were formed in 1996 and are owned 100% by our limited partners. Genesis Energy, LLC, our general partner, is a wholly-owned subsidiary. Our general partner has sole responsibility for conducting our business and managing our operations. We conduct our operations and own our operating assets through our subsidiaries and joint ventures.
On September 1, 2017, we acquired our trona and trona-based exploring, mining, processing, soda ash production, 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 convertible 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 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, soda ash production, 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 terminaling, 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

2. Summary of Significant Accounting Policies
Basis of Consolidation and Presentation
The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2018 and 2017 and our results of operations, statements of comprehensive income(loss), changes in partners’ capital and cash flows for the years ended December 31, 2018, 2017 and 2016. All intercompany balances and transactions have been eliminated. The accompanying Consolidated Financial Statements include Genesis Energy, L.P. and its subsidiaries.
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.
Joint Ventures
We participate in several joint ventures, including, in our offshore pipeline transportation segment, a 64% interest in Poseidon Oil Pipeline Company, L.L.C. (or "Poseidon"), a 25.7% interest in Neptune Pipeline Company, LLC and a 29% interest in Odyssey Pipeline L.L.C. (or "Odyssey"). We account for our investments in these joint ventures by the equity method of accounting. See Note 9.

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Use of Estimates

The preparation of our Consolidated Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. We based these estimates and assumptions on historical experience and other information that we believed to be reasonable under the circumstances. Significant estimates that we make include: (1) liability and contingency accruals, (2) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (3) estimates of future net cash flows from assets for purposes of determining whether impairment of those assets has occurred, and (4) estimates of future asset retirement obligations. Additionally, for purposes of the calculation of the fair value of awards under equity-based compensation plans, we make estimates regarding expected forfeiture rates of the rights and expected future distribution yield on our units. While we believe these estimates are reasonable, actual results could differ from these estimates. Changes in facts and circumstances may result in revised estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. We have no requirement for compensating balances or restrictions on cash. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal.

Accounts Receivable

We review our outstanding accounts receivable balances on a regular basis and record an allowance for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

Inventories

Our inventories are valued at the lower of cost and net realizable value. With the exception of our Alkali Business, cost is determined principally under the average cost method within specific inventory pools.

Within our Alkali Business, the cost of inventories are determined using the FIFO, except for materials and supplies which are recorded at average cost, and raw materials which are recorded at standard cost, which approximates actual cost.

Fixed Assets and Mineral Leaseholds

Property and equipment are carried at cost. Depreciation of property and equipment is provided using the straight-line method over the respective estimated useful lives of the assets. Asset lives are 5 to 40 years for pipelines and related assets, 20 to 30 years for marine vessels, 3 to 30 years for machinery and equipment, 3 to 7 years for transportation equipment, and 3 to 20 years for buildings and improvements, office equipment, furniture and fixtures and other equipment.

Interest is capitalized in connection with the construction of major facilities. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset’s estimated useful life.

Maintenance and repair costs are charged to expense as incurred. Costs incurred for major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset. Certain volumes of crude oil and refined products are classified in fixed assets, as they are necessary to ensure efficient and uninterrupted operations of the gathering businesses. These crude oil and refined products volumes are carried at their weighted average cost.

Long-lived assets are reviewed for impairment. An asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to be generated from the use and ultimate disposal of the asset. If the carrying value is determined to not be recoverable under this method, an impairment charge equal to the amount the carrying value exceeds the fair value is recognized. Fair value is generally determined from estimated discounted future net cash flows.

Mineral leaseholds are depleted over their useful lives as determined under the units of production method. When it has been determined that a mineral property can be economically developed as a result of establishing proven and probable reserves, the costs incurred to develop such property through the commencement of production are capitalized.

Deferred Charges on Marine Transportation Assets

Our marine vessels are required by US Coast Guard regulations to be re-certified after a certain period of time, usually every five years. The US Coast Guard states that vessels must meet specified "seaworthiness" standards to maintain required operating certificates. To meet such standards, vessels must undergo regular inspection, monitoring, and maintenance, referred to as "dry-docking." Typical dry-docking costs include costs incurred to comply with regulatory and vessel classification inspection requirements, blasting and steel coating, and steel replacement. We defer and amortize these costs to maintenance and repair expense over the length of time that the certification is supposed to last.

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Asset Retirement Obligations

Some of our assets have contractual or regulatory obligations to perform dismantlement and removal activities, and in some instances remediation, when the assets are abandoned. In general, our asset retirement obligations relate to future costs associated with the disconnecting or removing of our crude oil and natural gas pipelines and platforms, CO_2 pipelines, barge decommissioning, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The capitalized cost is depreciated over the useful life of the related asset. Accretion of the discount increases the liability and is recorded to expense. See Note 7.

Direct Financing Leasing Arrangements

For our direct financing leases, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction and is included in onshore facilities and transportation revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets.

We review our direct financing lease arrangements for credit risk. Such review includes consideration of the credit rating and financial position of the lessee. See Note 8.

Intangible and Other Assets

Intangible assets with finite useful lives are amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are amortizing our customer and supplier relationships, contract agreements, licensing agreements and trade name based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution of these assets to our cash flows is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. Intangible assets associated with lease or other items are being amortized on a straight-line basis.

We test intangible assets periodically to determine if impairment has occurred. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. No impairment has occurred of intangible assets in any of the periods presented.

Costs incurred in connection with our credit facilities and their related amendments have historically been capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the “effective interest” method of amortization. Certain of our capitalized debt issuance costs related to our respective issuances of notes are classified as reductions in long-term debt.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We evaluate, and test if necessary, goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. During the evaluation, we may perform a qualitative assessment of relevant events and circumstances to determine the likelihood of goodwill impairment. If it is deemed more likely than not that the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not necessary. We may also elect to exercise our unconditional option to bypass this qualitative assessment, in which case we would also calculate the fair value of the reporting unit. If the calculated fair value of the reporting unit exceeds its carrying value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its carrying value including associated goodwill amounts, the goodwill of that reporting unit is considered to be impaired and a charge to earnings must be recorded. The impact to earnings is the excess amount of carrying value over fair value, however the charge is not to exceed the total amount of goodwill allocated to the reporting unit under evaluation. See Note 10 for further information.

Environmental Liabilities

We provide for the estimated costs of environmental contingencies when liabilities are probable to occur and a reasonable estimate of the associated costs can be made. Ongoing environmental compliance costs, including maintenance and monitoring costs, are charged to expense as incurred.

Equity-Based Compensation

Our phantom units issued under our 2010 Long-Term Incentive Plan result in the payment of cash to our employees or directors of our general partner upon exercise or vesting of the related award. The fair value of our phantom units is equal to the

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market price of our common units. Our phantom units include both service-based and performance-based awards. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award. See Note 17 for more information.

Revenue Recognition

We recognize revenue across our operating segments upon the satisfaction of of their respective performance obligations. Refer to Note 3 for additional details on what constitutes a performance obligation in each of our businesses.

Cost of Sales and Operating Expenses

Onshore facilities and transportation operating and product costs include the cost to acquire the product and the associated costs to transport it to our terminal facilities, including storing, or to a customer for sale. Other than the cost of the products, the most significant costs we incur relate to transportation utilizing our fleet of trucks, railcars, terminals, barges and other vessels , including personnel costs, fuel and maintenance of our or third-party owned equipment. Additionally, costs to operate and maintain the integrity of our onshore pipelines are included herein. When we enter into buy/sell arrangements concurrently or in contemplation of one another with a single counterparty, we reflect the amounts of revenues and purchases for these transactions on a net basis in our Consolidated Statements of Operations as onshore facilities and transportation revenues.

Marine operating costs consist primarily of employee and related costs to man the boats, barges, and vessels, maintenance and supply costs related to general upkeep of the boats, barges, and vessels, and fuel costs which are often rebillable and passed through to the customer.

The most significant operating costs in our sodium minerals and sulfur services segment consist of the costs to operate our trona extraction and soda ash processing facilities, NaHS plants located at various refineries, caustic soda used in the process of processing the refiner’s sour gas, and costs to transport the soda ash, other alkali products, NaHS and caustic soda.

Pipeline operating costs consist primarily of power costs to operate pumping and platform equipment, personnel costs to operate the pipelines and platforms, insurance costs and costs associated with maintaining the integrity of our pipelines.

Income Taxes

We are a limited partnership, organized as a pass-through entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our Consolidated Statements of Operations, is included in the federal income tax returns of each partner.

Some of our corporate subsidiaries pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit not expected to be realized. Penalties and interest related to income taxes will be included in income tax expense in the Consolidated Statements of Operations.

Derivative Instruments and Hedging Activities

When we hold inventory positions in crude oil and petroleum products, we use derivative instruments to hedge exposure to price risk. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded in the Consolidated Balance Sheets as assets and liabilities based on the derivative’s fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. Changes in the fair value of cash flow hedges are deferred in Accumulated Other Comprehensive Income (“AOCI”) and reclassified into earnings when the underlying position affects earnings.

In addition, we have determined that certain provisions in our Class A Convertible Preferred units represent an embedded derivative which must be bifurcated and recorded at fair value, with changes in fair value in respective periods being recorded in our Consolidated Statements of Operations. See Note 19 for further information on these items.

Fair Value of Current Assets and Current Liabilities

The carrying amount of other current assets and other current liabilities approximates their fair value due to their short-term nature.

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Pension benefits

As a result of our acquisition of our Alkali Business, we now sponsor a defined benefit plan. The defined benefit plan is accounted for using actuarial valuations as required by GAAP. We recognize the funded status of the defined pension plan on the balance sheet and recognize changes in the funded status that arise during the period but are not recognized as components of net periodic benefit cost within other comprehensive income or loss.

Business Acquisitions

For acquired businesses, we apply the acquisition method and generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the date of acquisition. See Note 4 for more information regarding our acquisition accounting and recording of acquisition costs.

Recent and Proposed Accounting Pronouncements

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

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

We have reviewed the practical expedients that are available to facilitate the adoption process. We have elected 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. We have also elected to adopt the practical expedient relating to the separation of lease and non-lease components as well as the easement and right of way expedient. Finally we have elected to utilize the optional transition method which allows the company to only apply the new lease standard at the date of adoption while comparative periods will be presented under the previous lease guidance. We will not adopt the hindsight practical expedient.

As a result of adopting the new lease standard, we expect an impact on our consolidated balance sheet from the recognition of a right-of-use asset and the corresponding lease liability of less than $250 million. We do not expect a material impact to partners capital as a result of our transition adjustment.

In August 2016, the FASB issued guidance that addresses how certain cash receipts and payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash flow, and other Topics. The guidance 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 $15.3 million and $15.6 million from operating cash flows to investing cash flows for the years ended December 31, 2017 and 2016, respectively.

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 year ended December 31, 2018.

In January 2017, the FASB issued guidance to simplify the goodwill impairment testing at annual or interim periods. The guidance eliminates Step 2 from the goodwill impairment testing process, and any identified impairment charge would be simplified to be the difference between the carrying value and fair value of a reporting unit, but would not exceed the total amount of goodwill allocated to the reporting unit in question. The guidance is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2019. We elected to early adopt this standard as of January 1, 2017. See Note 10 for further information.

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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

Current Impact of New Revenue Recognition Guidance
The tables below summarize the impact of adoption on our consolidated balance sheet and statement of operations as of and for the year ended December 31, 2018:

	As of December 31, 2018		
Consolidated Balance Sheet	As Reported	Without adoption of ASC 606	Effect of Change Increase/(Decrease)
ASSETS			
Accounts receivable-trade, net	$323,462	$371,490	$ (48,028)
Inventories	73,531	69,367	4,164
Other Assets, net of amortization	121,707	49,466	72,241
LIABILITIES AND CAPITAL			
Other Long-Term Liabilities	259,198	232,927	26,271
Partners' Capital	1,690,799	1,688,693	2,106

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Consolidated Statement of Operations	Year ended December 31, 2018 As Reported	Without adoption of ASC 606	Effect of Change Increase/(Decrease)
Offshore pipeline transportation services	$284,544	$277,915	$ 6,629
Sodium minerals and sulfur services	1,174,434	1,071,634	102,800
Marine transportation	219,937	219,937	—
Onshore facilities and transportation	1,233,855	1,233,855	—
Total revenues	2,912,770	2,803,341	109,429
Onshore facilities and transportation product costs	1,037,688	1,037,688	—
Onshore facilities and transportation operating costs	89,042	89,042	—
Marine transportation operating costs	172,527	172,527	—
Sodium minerals and sulfur services operating costs	912,491	808,718	103,773
Offshore pipeline transportation operating costs	66,668	66,668	—
OPERATING INCOME	170,248	164,592	5,656

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 to provide firm 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. As a result, we have recorded revenue and the related cost of sales in the Consolidated Financial Statements for the year ended December 31, 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 year ended December 31, 2018:

	Year Ended December 31, Onshore Facilities & Transportation	Sodium Minerals & Sulfur Services	Offshore Pipeline Transportation	Marine Transportation	Consolidated
Fee-based revenues	$156,266	$—	$ 284,544	$ 219,937	$660,747
Product Sales	1,077,589	1,071,634	—	—	2,149,223
Refinery Services	—	102,800	—	—	102,800
	$1,233,855	$1,174,434	$ 284,544	$ 219,937	$2,912,770

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Explanation of Responses:

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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 simultaneously 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. Certain of our contracts include a single performance obligation to stand ready, on a 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, our performance obligation 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. The consideration we receive 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.

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Pipeline Loss Allowances
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 allow for us to make volumetric deductions 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 in the transaction price on a net basis. The net oil recorded is valued at the lower of cost or net realizable value using the market price of crude oil during the month the product was transported. 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 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.

Our performance obligation consists of 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 the 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 treating 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.

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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 at a 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 that we 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 December 31, 2018:

	Contract Assets Non-Current	Contract Liabilities Non-Current
Balance at January 1, 2018	$ 59,204	$ 19,864
Balance at December 31, 2018	72,241	26,271

During the year ended December 31, 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 December 31, 2018. However, ASC 606 provides 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. 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.

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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
2019	$ 74,200	$ 27,010	$ 65,436
2020	51,256	20,128	57,090
2021	34,562	—	20,139
2022	22,828	—	4,283
2023	12,076	—	—
Thereafter	123,371	—	—
Total	$ 318,293	$ 47,138	$ 146,948

4. Acquisitions

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 mines and processes trona from which it produces natural soda ash, also known as sodium carbonate (Na_2CO_3), as basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products. To finance that transaction and the related costs, we used proceeds from (i) a $550 million public offering of 6.50% senior unsecured notes due 2025 in August 2017, generating net proceeds of $540.1 million after issuance and underwriting fees, (ii) a $750 million private placement of Class A Convertible Preferred units in September 2017, generating net proceeds of $726.4 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 and the 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 the financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2017.

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

Accounts receivable	138,258
Inventories	34,929
Other current assets	13,254
Fixed assets	663,217
Mineral leaseholds	566,019
Intangible assets	800
Other assets	3,612
Accounts payable	(44,547)
Accrued Liabilities	(36,884)
Other long-term liabilities	(13,658)
Total Purchase Price	$1,325,000

Fixed assets identified in connection with our valuation and purchase price allocation include the related facilities, machinery and equipment associated with our Alkali Business, principally at our Green River, Wyoming operations. These assets will be depreciated under the straight line method and have useful lives ranging from 2 to 30 years. Mineral leaseholds include the trona reserves at our Green River, Wyoming facility and are depleted over their useful lives as determined by the units of production method. Other long-term liabilities contains various items including assumed employee benefit plan obligations. Other items principally consist of working capital items of our Alkali Business as acquired on September 1, 2017.

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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:

	Year Ended December 31, 2017
Revenues	277,011
Net income	42,014

The table below presents selected unaudited pro forma financial information incorporating the historical results of our Alkali Business. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2016 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. This pro forma information was prepared using historical financial data of our 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, 2016. Pro forma net income includes the effects of distributions on preferred units and interest expense on incremental borrowings. The dilutive effect of our Class A Convertible Preferred Units is calculated using the if-converted method.

	Year Ended December 31,	
	2017	2016
Pro forma consolidated financial operating results:		
Revenues	$2,549,438	$2,498,293
Net Income Attributable to Genesis Energy, L.P.	108,392	156,700
Net Income Available to Common Unitholders	42,768	91,076
Basic and diluted earnings per common unit:		
As reported net income per common unit	$0.50	$1.00
Pro forma net income per common unit, basic and dilutive	$0.35	$0.80

As relating to our Alkali Business acquisition, we incurred approximately $12.0 million in acquisition related costs through December 31, 2017, and incurred an additional $2.0 million during the year ended December 31, 2018. Such costs are included as "General and Administrative costs" on our Consolidated Statement of Operations.

5. Receivables

Accounts receivable – trade, net consisted of the following:

	December 31,	
	2018	2017
Accounts receivable - trade	$330,855	$503,917
Allowance for doubtful accounts	(7,393)	(8,468)
Accounts receivable - trade, net	$323,462	$495,449

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The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	December 31,		
	2018	2017	2016
Balance at beginning of period	$8,468	$6,505	$1,446
Charged to costs and expenses, net of recoveries	31	2,001	6,463
Amounts written off	(1,106)	(38)	(1,404)
Balance at end of period	$7,393	$8,468	$6,505

6. Inventories

The major components of inventories were as follows:

	December 31,	
	2018	2017
Petroleum products	$12,203	$8,731
Crude oil	8,379	29,873
Caustic soda	10,372	5,755
NaHS	12,400	8,277
Raw materials - Alkali Operations	5,952	4,550
Work-in-process - Alkali Operations	2,322	7,355
Finished goods, net - Alkali Operations	11,402	14,075
Materials and supplies, net - Alkali Operations	10,490	10,030
Other	11	7
Total	$73,531	$88,653

Inventories are valued at the lower of cost or net realizable value. The net realizable value of inventories were recorded below cost by approximately $1.0 million as of December 31, 2018 and were not recorded below cost as of December 31, 2017; therefore we reduced the value of inventory in our Consolidated Financial Statements for this difference.

Materials and supplies include chemicals, maintenance supplies, and spare parts which will be consumed in the mining of trona ore and production of soda ash processes.

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7. Fixed Assets, Mineral Leaseholds and Asset Retirement Obligations
Fixed Assets
Fixed assets consisted of the following:

	December 31, 2018	December 31, 2017
Crude oil pipelines and natural gas pipelines and related assets	$2,918,285	$3,028,657
Alkali facilities, machinery, and equipment	533,924	497,601
Onshore facilities, machinery, and equipment	639,023	692,364
Transportation equipment	20,102	21,483
Marine vessels	951,597	918,953
Land, buildings and improvements	222,242	223,186
Office equipment, furniture and fixtures	20,505	18,112
Construction in progress	94,025	151,768
Other	41,155	48,891
Fixed assets, at cost	5,440,858	5,601,015
Less: Accumulated depreciation	(1,023,825)	(734,986)
Net fixed assets	$4,417,033	$4,866,029

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

	December 31, 2018	December 31, 2017
Mineral leaseholds	566,019	566,019
Less: Accumulated depletion	(5,538)	(1,513)
Mineral leaseholds, net	$ 560,481	$ 564,506

Depreciation expense was $286.0 million, $226.0 million and $194.0 million for the years ended December 31, 2018, 2017, and 2016, respectively. Depletion expense was $4.0 million and $1.5 million for the years ended December 31, 2018 and 2017, respectively.

On October 11, 2018, we completed the divestiture of our Powder River Basin midstream assets, included in our Onshore Facilities and Transportation segment, and received total net proceeds of approximately $300 million. This sale resulted in a gain of $38.9 million recorded in Gains on assets sales in the Consolidated Statements of Operations. Additionally, we recorded an impairment expense of $21.2 million on our remaining non-core midstream assets in the Powder River Basin as the carrying value exceeded the fair value in the current market at December 31, 2018.

During 2018, we also recorded impairment expense of $82.0 million associated with certain of our non-core offshore gas assets in the Gulf of Mexico due to a change in contractual arrangements during the fourth quarter. Included in this amount is the acceleration in timing of the abandonment of one of our offshore hub platforms and pipelines and the write-off of its associated asset retirement obligation assets. The fair value of our assets was determined based on present value techniques.

During 2017, we sold certain non-core natural gas gathering and platform assets in the Gulf of Mexico included in our offshore pipeline transportation services segment, as well as certain onshore terminal facilities in West Texas included in our onshore facilities and transportation segment. These sales resulted in total gains on asset sales of $40.3 million for the year ended December 31, 2017 recorded in Gains on assets sales in the Consolidated Statements of Operations.

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Asset Retirement Obligations

We record AROs in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. For any AROs acquired, we record AROs based on the fair value measurement assigned during the preliminary purchase price allocation.

A reconciliation of our liability for asset retirement obligations is as follows:

December 31, 2016	$213,726
Accretion expense	11,008
Revisions in timing and estimated costs of AROs	7,146
Acquisitions	131
Divestitures	(7,649)
Settlements	(26,415)
Other	240
December 31, 2017	198,187
Accretion expense	10,509
Revisions in timing and estimated costs of AROs	44,319
Settlements	(13,150)
December 31, 2018	$239,865

At December 31, 2018 and December 31, 2017, $67.5 million and $20.9 million are included as current in "Accrued liabilities" on our Consolidated Balance Sheet, respectively. Revisions in timing and estimated costs during 2018 is primarily attributable to the accelerated timing and revised costs associated with the abandonment of certain of our non-core offshore gas assets in the Gulf of Mexico. The remainder of the ARO liability at each period is included in "Other long-term liabilities" on our Consolidated Balance Sheet.

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

2019	$9,928
2020	$10,997
2021	$9,313
2022	$9,892
2023	$10,586

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2018 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our Consolidated Financial Statements.

8. Net Investment in Direct Financing Leases

Our direct financing leases include a lease of the Northeast Jackson Dome (“NEJD”) Pipeline. Under the terms of the agreement, we are paid quarterly payments, which commenced August 2008. These quarterly payments are fixed at approximately $20.7 million per year during the lease term at an interest rate of 10.25%. At the end of the lease term in 2028, we will convey all of our interests in the NEJD Pipeline to the lessee for a nominal payment. There are requirements in our leases that would provide credit support should the credit rating of our lessee fall to certain levels, and at December 31, 2018, the required credit support has been provided.

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The following table lists the components of the net investment in direct financing leases:

	December 31,	
	2018	2017
Total minimum lease payments to be received	$195,280	$215,884
Unamortized initial direct costs	801	950
Less unearned income	(70,735)	(83,918)
Net investment in direct financing leases	125,346	132,916
Less current portion (included in other current assets)	(8,421)	(7,633)
Long-term portion of net investment in direct financing leases	$116,925	$125,283

At December 31, 2018, minimum lease payments to be received for each of the five succeeding fiscal years are $20.7 million.

9. Equity Investees

We account for our ownership in our joint ventures under the equity method of accounting (see Note 2 for a description of these investments). 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. At December 31, 2018 and 2017, the unamortized differences in carrying value totaled $366.4 million and $382.4 million, respectively. We amortize the differences in carrying value as a change in equity earnings.

In the first quarter of 2016, we purchased the remaining 50% interest in Deepwater Gateway, LLC for approximately $26.0 million (including adjustments for working capital), increasing our ownership interest to 100%. Consequently, we now consolidate Deepwater Gateway, LLC instead of accounting for our interest under the equity method.

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

	Year Ended December 31,		
	2018	2017	2016
Genesis’ share of operating earnings	$59,255	$66,814	$63,805
Amortization of differences attributable to Genesis' carrying value of equity investments	(15,629)	(15,768)	(15,861)
Net equity in earnings	$43,626	$51,046	$47,944
Distributions received	$71,714	$82,898	$87,220

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The following tables present the combined balance sheet information for the last two years and income statement data for the last three years for our equity investees (on a 100% basis) including the effects of the change in our ownership interest due to the Deepwater acquisition as previously discussed:

	December 31,	
	2018	2017
BALANCE SHEET DATA:		
Assets		
Current assets	$34,005	$34,381
Fixed assets, net	346,864	362,214
Other assets	15,469	14,927
Total assets	$396,338	$411,522
Liabilities and equity		
Current liabilities	$18,897	$23,289
Other liabilities	250,742	249,610
Equity	126,699	138,623
Total liabilities and equity	$396,338	$411,522

	Year Ended December 31,		
	2018	2017	2016
INCOME STATEMENT DATA:			
Revenues	$180,056	$191,078	$193,038
Operating Income	$129,160	$139,604	$122,836
Net Income	$115,669	$134,479	$118,175

Poseidon's revolving credit facility

Borrowings under Poseidon’s revolving credit facilities, 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 its 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 consolidated financial statements.

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10. Intangible Assets, Goodwill and Other Assets

Intangible Assets

The following table reflects the components of intangible assets being amortized at December 31, 2018 and 2017:

		December 31, 2018			December 31, 2017		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Sodium Minerals and Sulfur Services:							
Customer relationships	5	$94,654	$ 94,654	$—	$94,654	$ 92,493	$2,161
Licensing agreements	6	38,678	38,678	—	38,678	36,528	2,150
Non-compete agreement	3	800	356	444	800	89	711
Segment total		134,132	133,688	444	134,132	129,110	5,022
Onshore Facilities & Transportation:							
Customer relationships	5	35,430	35,123	307	35,430	35,082	348
Intangibles associated with lease	15	13,260	5,407	7,853	13,260	4,933	8,327
Segment total		48,690	40,530	8,160	48,690	40,015	8,675
Marine contract intangible	5	27,000	17,100	9,900	27,000	11,700	15,300
Offshore pipeline contract intangibles	19	158,101	28,431	129,670	158,101	20,109	137,992
Other	5	30,947	16,519	14,428	28,900	13,483	15,417
Total		$398,870	$ 236,268	$162,602	$396,823	$ 214,417	$182,406

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The onshore facilities and transportation lease relates to a terminal facility in Shreveport, Louisiana. The marine contract intangible relates to the contracts we assumed in the purchase of the M/T American Phoenix in November 2014.

The offshore pipeline contract intangibles relate to customer contracts surrounding certain transportation agreements with producers in the Lucius production area in Southeast Keathley Canyon, which support our SEKCO pipeline identified in connection with our purchase price allocation surrounding the Enterprise Acquisition.

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The onshore facilities and transportation lease, marine contract, offshore pipeline contract intangibles and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $21.8 million, $23.6 million and $24.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The following table reflects our estimated amortization expense for each of the five subsequent fiscal years:

	2019	2020	2021	2022	2023
Sodium Minerals and Sulfur Services:					
Non Compete	267	177	—	—	—
Onshore Facilities & Transportation:					
Customer relationships	39	38	37	35	34
Intangibles associated with lease	474	474	474	474	474
Marine contract intangibles	5,400	4,500	—	—	—
Offshore pipeline contract intangibles	8,321	8,321	8,321	8,321	8,321
Other	3,153	3,132	2,011	1,853	1,568

Total	$17,654	$16,642	$10,843	$10,683	$10,397

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Goodwill

The carrying amount of goodwill in sodium minerals and sulfur services was $301.9 million in December 31, 2018 and 2017. During 2018, we recognized a goodwill impairment loss of $23.1 million related to our onshore facilities and transportation segment during the period. The goodwill impairment was specifically related to our supply and logistics reporting unit, that primarily includes our legacy crude oil and refined products marketing and trucking businesses. Due to our efforts to rightsize these businesses, along with the volatility of crude oil prices and the impact this volatility has on the availability of crude oil and heavy refined products for us to market, the fair value of the reporting unit was determined to be lower than the carrying value of the reporting unit, including goodwill. The fair value was derived using a discounted cash flow present value technique.

Other Assets

Other assets consisted of the following:

	December 31,	
	2018	2017
CO_2 volumetric production payments, net of amortization	$890	$2,175
Deferred marine charges, net [(1)]	28,175	30,246
Contract assets [(2)]	72,241	—
Other deferred costs and deposits	20,401	24,207
Other assets, net of amortization	$121,707	$56,628

(1) See discussion of deferred charges on marine transportation assets in the Summary of Accounting Policies (Note 2)

(2) See Revenue Recognition (Note 3) for discussion on the circumstances that result in the recognition of contract assets.

The CO_2 assets are being amortized on a units-of-production method. We recorded amortization of $1.3 million in 2018, $1.3 million in 2017 and $3.9 million in 2016.

11. Debt

At December 31, 2018 and 2017, our obligations under debt arrangements consisted of the following:

	December 31, 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	$970,100	$ —	$970,100	$1,099,200	$ —	1,099,200
5.750% senior unsecured notes	—	—	—	145,170	1,303	143,867
6.750% senior unsecured notes	750,000	12,763	737,237	750,000	16,077	733,923
6.000% senior unsecured notes	400,000	4,624	395,376	400,000	5,691	394,309
5.625% senior unsecured notes	350,000	4,820	345,180	350,000	5,717	344,283
6.500% senior unsecured notes	550,000	8,241	541,759	550,000	9,462	540,538
6.250% senior unsecured notes	450,000	$ 7,189	442,811	450,000	8,002	441,998
Total long-term debt	$3,470,100	$ 37,637	$3,432,463	$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 Consolidated Balance Sheet) were $10.8 million and $14.1 million as of December 31, 2018 and December 31, 2017, respectively.

Senior Secured Credit Facility

In October 2018, we amended our credit agreement to, among other things, make certain technical amendments related to the sale of our Powder River Basin midstream assets. 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 interest rate on borrowings may be based on an alternate base rate or a Eurodollar rate, at our option. The alternate base rate is equal to the sum of (a) the greatest of (i) the prime rate as established by the administrative agent for the credit facility, (ii) the federal funds effective rate plus 0.5% of 1% and (iii) the LIBOR rate for a one-month maturity plus 1% and (b) the applicable margin. The Eurodollar rate is equal to the sum of (a) the LIBOR rate for the applicable

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interest period multiplied by the statutory reserve rate and (b) the applicable margin. 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, depending on our leverage ratio. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At December 31, 2018, the applicable margins on our borrowings were 1.75% for alternate base rate borrowings and 2.75% for Eurodollar rate borrowings.

- Letter of credit fees range from 1.50% to 3.00% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2018, our letter of credit rate was 2.75%.
- We pay a commitment fee on the unused portion of the $1.7 billion maximum facility amount. The commitment fee on the unused committed amount will range from 0.25% to 0.50% per annum depending on our leverage ratio (0.50% at December 31, 2018).
- Our credit facility contains a $300 million accordion feature, giving us the ability to expand the size of the facility up to $2.0 billion for acquisitions or growth projects, subject to lender consent.

Our credit facility contains customary covenants (affirmative, negative and financial) that could limit the manner in which we may conduct our business. As defined in our credit facility, we are required to meet three primary financial metrics—a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. Our credit agreement provides for the temporary inclusion of certain pro forma adjustments to the calculations of the required ratios following material acquisitions. In general, our leverage ratio calculation compares our consolidated funded debt (including outstanding notes we have issued) to EBITDA (as defined and adjusted in accordance with the credit facility) and cannot exceed 5.50 to 1.00. Our senior secured leverage ratio excludes outstanding debt under senior unsecured notes and cannot exceed 3.75 to 1.00. Our interest coverage ratio calculation compares EBITDA (as defined and adjusted in accordance with the credit facility) to interest expense and must be greater than 3.00 to 1.00 (2.75 to 1.00 during an acquisition period).

At December 31, 2018, we had $970.1 million borrowed under our credit facility, with $17.8 million of the borrowed amount designated as a loan under the inventory sublimit. Our credit agreement allows up to $100 million of the capacity to be used for letters of credit, of which $1.2 million was outstanding at December 31, 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 of May 9, 2022. The total amount available for borrowings under our credit facility at December 31, 2018 was $728.7 million. Our credit facility does not include a “borrowing base” limitation except with respect to our inventory loans.

Senior Unsecured Notes

On February 8, 2013, we issued $350 million of aggregate principal amount of 5.75% senior unsecured notes due February 15, 2021 (the "2021 Notes"). On December 11, 2017, $204.8 million of these notes were validly tendered and repaid upon the issuance of our $450 million unsecured notes issued on December 11, 2017 as discussed below. A total loss of approximately $6.2 million for the tender is recorded to "Other income/(expense), net" in our Consolidated Statements of Operations as of December 31, 2017. 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 loss is recorded as "Other income/(expense), net" in our Consolidated Statements of Operations for the year ended December 31, 2018.

On May 15, 2014, we issued $350 million in aggregate principal amount of 5.625% senior unsecured notes due December 15, 2024 (the "2024 Notes"). Our 2024 Notes were sold at face value. Interest payments are due on June 15 and December 15 of each year with the initial interest payment due December 15, 2014. Our 2024 Notes mature on June 15, 2024. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.

On May 21, 2015, we issued $400 million in aggregate principal amount of 6.00% senior unsecured notes due May 15, 2023 (the "2023 Notes"). Interest payments are due on May 15 and November 15 of each year with the

initial interest payment due November 15, 2015. Our 2023 Notes mature on May 15, 2023. We used a portion of the proceeds from those notes to effectively redeem all of our outstanding $350 million, 7.875% senior unsecured notes due 2018, using a combination of public tender offer and our redemption rights relating to those notes.
On July 23, 2015, we issued $750 million in aggregate principal amount of 6.75% senior unsecured notes due August 1, 2022 (the "2022 Notes"). Interest payments are due on February 1 and August 1 of each year with the initial interest payment due February 1, 2016. Our 2022 Notes mature on August 1, 2022. That issuance generated net proceeds of $728.6 million net of issuance discount and underwriting fees. The net proceeds were used to fund a portion of the purchase price for our Enterprise acquisition.

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

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. That issuance generated net 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.

We have the right to redeem each of our series of notes beginning on specified dates as summarized below, at a premium to the face amount of such notes that varies based on the time remaining to maturity on such notes. Additionally, we may redeem up to 35% of the principal amount of each of our series of notes with the proceeds from an equity offering of our common units during certain periods. A summary of the applicable redemption periods is provided in the table below.

	2022 Notes	2023 Notes	2024 Notes	2025 Notes	2026 Notes
Redemption right beginning on	August 1, 2018	May 15, 2018	June 15, 2019	October 1, 2020	February 15, 2021
Redemption of up to 35% of the principal amount of notes with the proceeds of an equity offering permitted prior to	August 1, 2018	May 15, 2018	June 15, 2019	October 1, 2020	February 15, 2021

Guarantees of our 2022, 2023, 2024, 2025 and 2026 Notes will be released under certain circumstances, including (i) in connection with any sale or other disposition of (a) all or substantially all of the properties or assets of a guarantor (including by way of merger or consolidation) or (b) all of the capital stock of such guarantor, in each case, to a person that is not a restricted subsidiary of the Partnership (ii) if the Partnership designates any restricted subsidiary that is a guarantor as an unrestricted subsidiary, (iii) upon legal defeasance, covenant defeasance or satisfaction and discharge of the applicable indenture, (iv) upon the liquidation or dissolution of such guarantor, or (v) at such time as such guarantor ceases to guarantee any other indebtedness of either of the issuers and any other guarantor.

Covenants and Compliance

Our credit agreement and the indenture governing the senior notes contain cross-default provisions. Our credit documents prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, those agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

A default under our credit documents would permit the lenders thereunder to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit facility, our ability to make distributions of “available cash” is not restricted. As of December 31, 2018, we were in compliance with the financial covenants contained in our credit facility and indenture.

12. Partners’ Capital, Mezzanine Equity and Distributions

At December 31, 2018, our outstanding equity consisted of 122,539,221 Class A common units and 39,997 Class B common units. The Class A units are traditional common units in us. The Class B units are identical to the Class A units and, accordingly, have voting and distribution rights equivalent to those of the Class A units, and, in addition, the Class B units have the right to elect all of our board of directors and are convertible into Class A units under certain circumstances, subject to certain exceptions.

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Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments, or other agreements; or
  - provide funds for distributions to our unitholders for any one or more of the next four quarters;
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

We paid distributions in 2019, 2018 and 2017 as follows:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2016			
4th Quarter	February 14, 2017	$0.7100	$83,765
2017			
1st Quarter	May 15, 2017	$0.7200	$88,257
2nd Quarter	August 14, 2017	$0.7225	$88,563
3rd Quarter	November 14, 2017	$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	$0.5400	$66,193
4th Quarter	February 14, 2019	$0.5500	$67,419

Equity Issuances and Contributions

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

On March 24, 2017, we issued 4,600,000 Class A common units in a public offering at a price of $30.65 per unit, which included the exercise by the underwriters of an option to purchase up to 600,000 additional common units from us. We received proceeds, net of offering costs, of approximately $140.5 million from that offering.

On July 27, 2016, we issued 8,000,000 Class A common units in a public offering at a price of $37.90 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $298.5 million from that offering. We used those proceeds to repay a portion of the borrowings outstanding under our credit facility.

The new common units issued in 2017 and 2016 to the public for cash were as follows:

Period	Purchaser of Common Units	Units	Gross Unit Price	Issuance Value	Costs	Net Proceeds
March 2017	Public	4,600	$ 30.65	$140,990	$(477)	$140,513
July 2016	Public	8,000	$ 37.90	$303,200	$(4,748)	$298,452

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Class A Convertible Preferred Units

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

Each of our preferred units accumulate quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374), subject to certain adjustments. With respect to any quarter ending on or prior to March 1, 2019, we have the option to pay to the holders of our preferred units the applicable distribution amount in cash, preferred units, or any combination thereof. If we elect to pay all or any portion of a quarterly distribution amount in preferred units, the number of such preferred units will equal the product of (i) the number of then outstanding preferred units and (ii) the quarterly rate. We have elected to pay all distributions from inception through the quarter ending December 31, 2018 with additional preferred units. For each quarter ending after March 1, 2019, we must pay all distribution amounts in respect of our preferred units in cash.

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

Upon certain events involving certain changes of control in which more than 90% of the consideration payable to the holders of our common units is payable in cash, our preferred units will automatically convert into common units at a conversion ratio equal to the greater of (a) the then applicable conversion rate and (b) the quotient of (i) the product of (A) the sum of (1) the Issue Price and (2) any accrued and accumulated but unpaid distributions on our preferred units, and (B) a premium factor (ranging from 115% to 101% depending on when such transaction occurs) plus a prorated portion of unpaid partial distributions, and (ii) the volume weighted average price of the common units for the 30 trading days prior to the execution of definitive documentation relating to such change of control.

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

For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our preferred units may make a one-time election to reset the quarterly distribution amount (a “Rate Reset Election”) to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 110% of the Issue Price. To become effective, the Rate Reset Election requires approval of holders of at least a majority of our then outstanding preferred units and such majority must include each of our initial purchasers (or any affiliate to whom they have transferred their preferred units) if such initial purchaser (including its affiliates) holds at least 25% of the then outstanding preferred units.

Upon the occurrence of a Rate Reset Election, we may redeem our preferred units for cash, in whole or in part (subject to certain minimum value limitations) for an amount per preferred unit equal to such preferred unit's liquidation value (equal to the Issue Price plus any accrued and accumulated but unpaid distributions, plus a prorated portion of certain unpaid partial distributions in respect of the immediately preceding quarter and the current quarter) multiplied by (i) 110%, prior to

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September 1, 2024, and (ii) 105% thereafter. Each holder of our preferred units may elect to convert all or any portion of its preferred units into common units initially on a one-for-one basis (subject to customary adjustments and an adjustment for accrued and accumulated but unpaid distributions and limitations) at any time after September 1, 2019 (or earlier upon a change of control, liquidation, dissolution or winding up), provided that any conversion is for at least $50 million or such lesser amount if such conversion relates to all of a holder's remaining preferred units or has otherwise been approved by us.

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

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

The Rate Reset Election of these preferred units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Consolidated Balance Sheet. See further information in Note 19. The preferred units themselves are classified as mezzanine capital on our Consolidated Balance Sheet.

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 which is outside of our control. Therefore, we present them as temporary equity in the mezzanine section of the Consolidated Balance Sheet. The preferred units have been recorded at their issuance date fair value, net of issuance costs. Because our preferred units are not currently redeemable and we do not have plans or expect any events which 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 redemption first becomes probable and the date the units can first be redeemed.

As discussed above, a portion of the net proceeds were allocated to the Preferred Distribution Rate Reset Election and recorded in Other long term liabilities on the Consolidated Balance Sheet as described below (as of the inception date):

	September 1, 2017
Transaction price, gross	750,000
Transaction cost to other third parties	(23,581)
Transaction price, net	726,419

Allocation of Net Transaction Price	
Preferred Units, net	691,969
Preferred Distribution Rate Reset Election (Note 19)	34,450
	726,419

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Preferred unit distributions are recognized on the date in which they are declared. Paid in kind distributions were declared and issued as follows:

Distribution Declared	Date Issued	Number of Units	Total Amount
2017			
November 2017	November 14, 2017	162,234	$ 5,469
2018			
January 2018	February 14, 2018	490,252	$ 16,526
April 2018	May 15, 2018	500,976	$ 16,888
July 2018	August 14, 2018	511,934	$ 17,257
October 2018	November 14, 2018	523,132	$ 17,635

The following table shows the change in our Class A Convertible Preferred Units from initial measurement at September 1, 2017 to December 31, 2018:

	Class A Convertible Preferred Units	
	Units	$
December 31, 2016	—	$—
Issuance of Preferred Units, net	22,249,494	726,419
Allocation to Preferred Distribution Rate Reset Election (Note 19)	—	(34,450)
Distributions paid-in-kind	162,234	5,469
Allocation of Distributions paid-kind to Preferred Distribution Rate Reset Election (Note 19)	—	(287)
Balance as of December 31, 2017	22,411,728	$ 697,151
Distributions paid-in-kind	2,026,294	68,306
Allocation of Distributions paid-kind to Preferred Distribution Rate Reset Election (Note 19)	—	(3,991)
Balance as of December 31, 2018	24,438,022	$ 761,466

Net income(loss) attributable to common unitholders is reduced by Preferred Unit distributions that accumulated during the period. During 2018, net income attributable to common unitholders was reduced by $69.8 million as a result of distributions that accumulated during the period. With respect to our Class A Convertible Preferred Units relating to the fourth quarter of 2018, we declared a payment-in-kind ("PIK") of the quarterly distribution, which resulted in the issuance of an additional 534,576 Class A Convertible Preferred Units. This PIK amount equates to a distribution of $0.7374 per Class A Convertible Preferred Unit for the 2018 Quarter, or $2.9496 annualized. These distributions were paid on February 14, 2019 to preferred unitholders holders of record at the close of business January 31, 2019.

13. Net Income (Loss) Per Common Unit

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

The dilutive effect of the Class A Convertible Preferred units is calculated using the if-converted method. Under the if-converted method, the Class A Preferred units are assumed to be converted at the beginning of the period (beginning with their respective issuance date), and the resulting common units are included in the denominator of the diluted net income per common unit calculation for the period being presented. Distributions declared in the period and undeclared distributions that accumulated during the period are added back to the numerator for purposes of the if-converted calculation. For the year ended December 31, 2018, the effect of the assumed conversion of the 24,438,022 Class A convertible 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 (loss) and weighted average units used in computing basic and diluted net income (loss) per common unit (in thousands, except per unit amounts):

	Year Ended December 31,		
	2018	2017	2016
Net Income (Loss) Attributable to Genesis Energy L.P.	$(6,075)	$82,647	$113,249
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(69,801)	(21,995)	—
Net Income (Loss) Available to Common Unitholders	$(75,876)	$60,652	$113,249
Weighted Average Outstanding Units	122,579	121,546	113,433
Basic and Diluted Net Income (Loss) per Common Unit	$(0.62)	$0.50	$1.00

14. Business Segment Information

Our operations consist of four operating segments (see Note 1 for discussion of segment reporting change):

- 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 of high sulfur (or “sour”) gas streams for refineries to remove the sulfur, and selling the related by-product, NaHS;
- Onshore Facilities and Transportation – terminaling, 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 charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our legacy stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases.

Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes, where relevant, and capital investment.

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Segment information for each year presented below is as follows:

	Offshore Pipeline Transportation	Sodium Minerals & Sulfur Services	Onshore Facilities & Transportation	Marine Transportation	Total
Year Ended December 31, 2018					
Segment Margin [(a)]	$ 285,014	$260,488	$ 119,918	$ 47,338	$712,758
Capital expenditures [(b)]	$ 4,703	$74,712	$ 51,110	$ 30,868	$161,393
Revenues:					
External customers	$ 284,544	$1,181,578	$ 1,240,382	$ 206,266	$2,912,770
Intersegment [(c)]	—	(7,144)	(6,527)	13,671	$—
Total revenues of reportable segments	$ 284,544	$1,174,434	$ 1,233,855	$ 219,937	$2,912,770
Year Ended December 31, 2017					
Segment Margin [(a)]	$ 317,540	$130,333	$ 96,376	$ 50,294	$594,543
Capital expenditures [(b)]	$ 8,815	$1,354,469	$ 149,123	$ 68,414	$1,580,821
Revenues:					
External customers	$ 319,455	$470,789	$ 1,044,083	$ 194,050	$2,028,377
Intersegment [(c)]	(1,216)	(8,167)	(1,854)	11,237	$—
Total revenues of reportable segments	$ 318,239	$462,622	$ 1,042,229	$ 205,287	$2,028,377
Year Ended December 31, 2016					
Segment Margin [(a)]	$ 336,620	$79,508	$ 83,364	$ 70,079	$569,571
Capital expenditures [(b)]	$ 46,277	$2,274	$ 316,638	$ 78,804	$443,993
Revenues:					
External customers	$ 332,514	$180,665	$ 993,103	$ 206,211	$1,712,493
Intersegment [(c)]	2,165	(9,162)	187	6,810	$—
Total revenues of reportable segments	$ 334,679	$171,503	$ 993,290	$ 213,021	$1,712,493

Total assets by reportable segment were as follows:

	December 31, 2018	December 31, 2017	December 31, 2016
Offshore pipeline transportation	2,359,013	2,486,803	2,575,335
Sodium minerals and sulfur services	1,844,845	1,848,188	395,043
Onshore facilities and transportation	1,431,910	1,927,976	1,875,403
Marine transportation	800,243	824,777	813,722
Other assets	43,060	49,737	43,089
Total consolidated assets	$ 6,479,071	$ 7,137,481	$ 5,702,592

(a) A reconciliation of total Segment Margin to net income (loss) attributable to Genesis Energy, L.P. for each year 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. In addition to construction of growth projects, capital spending in our sodium minerals and sulfur services segment included $1.3 billion during the year ended December 31, 2017 related to the acquisition of our Alkali Business. During the year ended December 31, 2016, capital expenditures in our offshore pipeline transportation segment included $35.1 million related to the acquisition of the remaining 50% ownership in Deepwater Gateway.

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

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Reconciliation of total Segment Margin to net income (loss) attributable to Genesis Energy, L.P.:

	Year Ended December 31,		
	2018	2017	2016
Total Segment Margin	$712,758	$594,543	$569,571
Corporate general and administrative expenses	(64,683)	(60,029)	(40,905)
Depreciation, depletion, amortization and accretion	(317,186)	(262,021)	(230,563)
Interest expense	(229,191)	(176,762)	(139,947)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income [1]	(28,088)	(31,852)	(39,276)
Non-cash items not included in Segment Margin	9,698	(14,305)	(3,221)
Cash payments from direct financing leases in excess of earnings	(7,633)	(6,921)	(6,277)
Loss on extinguishment of debt	(3,339)	(6,242)	—
Differences in timing of cash receipts for certain contractual arrangements [2]	6,629	17,540	13,253
Gain on sales of assets	42,264	40,311	—
Other, net	—	(2,985)	(6,044)
Non-cash provision for leased items no longer in use	476	(12,589)	—
Income tax expense	(1,498)	3,959	(3,342)
Impairment expense	(126,282)	—	—
Net income (loss) attributable to Genesis Energy, L.P.	$(6,075)	$82,647	$113,249

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

(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.

15. Transactions with Related Parties

Transactions with related parties were as follows:

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Sales of CO_2 to Sandhill Group, LLC [1]	$1,233	$2,820	$3,097
Revenues from services and fees to Poseidon Oil Pipeline Company, LLC [2]	12,557	12,357	10,844
Revenues from product sales to ANSAC	373,606	124,536	—
Expenses:			
Amounts paid to our CEO in connection with the use of his aircraft	$660	$660	$660
Charges for products purchased from Poseidon Oil Pipeline Company, LLC [2]	994	986	1,007
Charges for services from ANSAC	5,284	2,242	—

(1) We owned a 50% interest in Sandhill Group, LLC which was sold in the third quarter of 2018.

(2) We own a 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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Transactions with Unconsolidated Affiliates

Poseidon

We 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 years ended December 31, 2018, 2017 and 2016 reflect $8.6 million, $8.4 million and $7.9 million, respectively, of fees we earned through the provision of services under that agreement. At December 31, 2018, and 2017, Poseidon Oil Pipeline Company, LLC owed us $2.4 million and $2.2 million, respectively, for services rendered.

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 the Alkali Business on a stand-alone basis. We also benefit from favorable shipping rates for our direct exports when using ANSAC to arrange for ocean transport.

Net sales to ANSAC were $373.6 million and $124.5 million for the years ended December 31, 2018 and 2017. The costs charged to us by ANSAC, included in operating costs, were $5.3 million and $2.2 million for the year ended December 31, 2018 and 2017. The 2017 period includes net sales and costs from September 1, 2017 (our acquisition date) to December 31, 2017.

As of December 31, 2018 and 2017, our receivables from and payables to ANSAC were:

	December 31 2018	December 31 2017
Receivables:		
ANSAC	$ 60,594	$ 74,490
Payables:		
ANSAC	$ 815	$ 1,223

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

16. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2018	2017	2016
(Increase) decrease in:			
Accounts receivable	$130,573	$(140,948)	$(9,859)
Inventories	20,963	49,055	(54,361)
Deferred charges	(5,826)	(3,622)	(3,902)
Other current assets	9,337	(410)	3,059
Increase (decrease) in:			
Accounts payable	(130,991)	97,569	(17,426)
Accrued liabilities	(26,208)	8,512	(8,161)
Net changes in components of operating assets and liabilities	$(2,152)	$10,156	$(90,650)

Payments of interest and commitment fees were $228.3 million, $168.3 million and $157.4 million during the years ended December 31, 2018, 2017 and 2016, respectively. We capitalized interest of $3.4 million, $15.0 million and

$26.6 million during the years ended December 31, 2018, 2017 and 2016.

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During the years ended December 31, 2018, 2017 and 2016, we paid taxes of $0.2 million, $1.0 million and $1.3 million.
At December 31, 2018, 2017 and 2016, we had incurred liabilities for fixed and intangible asset additions totaling $9.4 million, $39.7 million and $33.7 million, respectively, which had not been paid at the end of the year. Therefore, these amounts were not included in the caption "Payments to acquire fixed and intangible assets" under Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

17. Equity-Based Compensation Plans
2010 Long Term Incentive Plan
In 2010, we adopted the 2010 Long-Term Incentive Plan (the "2010 Plan"). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to members of our board of directors and employees who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights ("DERs") are tandem rights to receive on a quarterly basis a cash amount per phantom unit equal to the amount of cash distributions paid per common unit. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the "G&C Committee") of our board of directors. The G&C Committee (at its discretion) designates participants in the 2010 Plan, determines the types of awards to grant to participants, determines the number of units to be covered by any award, and determines the conditions and terms of any award including vesting, settlement and forfeiture conditions.
The compensation cost associated with the phantom units is re-measured each reporting period based on the market value of our common units, and is recognized over the vesting period. The liability recorded for the estimated amount to be paid to the participants under the 2010 Plan is adjusted to recognize changes in the estimated compensation cost and vesting. Management's estimates of the fair value of these awards granted in 2018 are adjusted for assumptions about expected forfeitures of units prior to vesting. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award.
During 2018, we granted 28,484 phantom units with tandem DERs at a weighted average grant fair value of $22.12 per unit. During 2017, we granted 297,214 phantom units with tandem DERs at a weighted average grant date fair value of $32.37 per unit. During 2016, we granted 339,584 phantom units with tandem DERs at a weighted average grant date fair value of $30.71 per unit. The phantom units granted during 2018 were made only to directors. Awards to management and other key employees during 2018 were made under the 2018 LTIP plan, and were non-equity awards. The phantom units granted during 2017 and 2016 were both service-based and performance-based awards. The service-based awards vest on the third anniversary of the date of grant. Performance-based phantom unit awards granted in 2016 and 2017 will vest on the third anniversary of issuance, in an amount ranging from 0% to 150% of the targeted number of phantom units, if certain quarterly cash distribution per common unit targets are achieved in the fourth quarter of 2019 and 2020, respectively. If the quarterly cash distribution per common unit is below the threshold target, all of the performance-based phantom units granted will be forfeited.

A summary of our phantom unit activity for our service-based and performance-based awards is set forth below:

	Service-Based Awards			Performance-Based Awards		
	Number of Phantom Units	Average Grant Date Fair Value	Total Value (in thousands)	Number of Phantom Units	Average Grant Date Fair Value	Total Value (in thousands)
Unvested at December 31, 2017	239,837	$ 34.81	$ 8,349	582,375	$ 34.73	$ 20,228
Granted	28,484	$ 22.12	630	—	$ —	—
Forfeited	(17,073)	$ 31.46	(537)	(67,266)	$ 33.49	(2,253)
Settled	(55,309)	$ 44.92	(2,484)	(137,103)	$ 45.40	(6,224)
Unvested at December 31, 2018	195,939	$ 30.40	$ 5,958	378,006	$ 31.09	$ 11,751

At December 31, 2018, we estimated the unrecognized compensation cost of our phantom awards to be approximately $0.6 million to be recognized over a weighted average period of approximately 0.8 years. We recorded a charge of $2.1 million and a credit of $3.4 million to compensation expense for the years ended December 31, 2018 and 2017, respectively. Our liability for these awards totaled $3.3 million and $3.2 million at December 31, 2018 and 2017, respectively.

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Equity-Based Compensation Plan Expense

Equity-based compensation expense during the three years ended December 31, 2018 was as follows:

	Expense Related to Equity-Based Compensation Plans		
Consolidated Statement of Operations	2018	2017	2016
Onshore facilities and transportation operating costs	$140	$(1,137)	$1,688
Marine transportation operating costs	183	(483)	1,089
Sodium minerals and sulfur services operating costs	112	(533)	547
Offshore pipeline operating costs	297	(152)	681
General and administrative expenses	1,239	(2,272)	4,575
Total	$1,971	$(4,577)	$8,580

18. Major Customers and Credit Risk

Due to the nature of our onshore facilities and transportation operations, a disproportionate percentage of our trade receivables constitute obligations of refiners, large crude oil producers and integrated oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of accounts owed by integrated and large independent energy companies with stable payment histories. The credit risk related to contracts which are traded on the NYMEX is limited due to daily margin requirements and other NYMEX requirements.

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

During 2018, 2017 and 2016 our largest customer was Shell Oil Company, which accounted for 11%, 13%, and 12% of total revenues, respectively. The revenues from Shell Oil Company in all three years relate primarily to our onshore facilities and transportation operations.

In addition, as discussed in Note 15, we are a member of 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. Given this relationship, a large portion of our soda ash production is sold to ANSAC. As such, a disproportionate amount of our trade receivables and sales in our sodium minerals and sulfur services segment are related to ANSAC.

19. 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

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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 Consolidated Statement of Operations.

In accordance with NYMEX requirements, we fund the margin associated with our loss positions on commodity derivative contracts traded on the NYMEX. The amount of the margin is adjusted daily based on the fair value of the commodity contracts. The margin requirements are intended to mitigate a party’s exposure to market volatility and the associated contracting party risk. We offset fair value amounts recorded for our NYMEX derivative contracts against margin funding as required by the NYMEX in Current Assets - Other in our Consolidated Balance Sheets.

Additionally, in 2018 we 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 December 31, 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)	56	—
Weighted average contract price per bbl	$ 53.11	—
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	293	234
Weighted average contract price per bbl	$ 49.85	$ 49.37
Natural gas swaps:		
Contract volumes (10,000 MMBTU)	502	—
Weighted average price differential per MMBTU	$ 0.62	—
Natural gas futures:		
Contract volumes (10,000 MMBTU)	137	590
Weighted average contract price per MMBTU	$ 3.53	$ 2.91
Diesel futures:		
Contract volumes (1,000 bbls)	2	2
Weighted average contract price per bbl	$ 1.89	$ 1.85
NYM RBOB Gas futures:		
Contract volumes (42,000 gallons)	2	1
Weighted average contract price per gallon	$ 1.35	$ 1.29
Fuel oil futures:		
Contract volumes (1,000 bbls)	382	40
Weighted average contract price per bbl	$ 51.41	$ 49.94
Crude oil options:		

Contract volumes (1,000 bbls)	26	—
Weighted average premium received	$ 2.66	$ —

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Financial Statement Impacts

The following table summarizes the accounting treatment and classification of our derivative instruments on our Consolidated Financial Statements.

		Impact of Unrealized Gains and Losses	
Derivative Instrument	Hedged Risk	Consolidated Balance Sheets	Consolidated Statements of Operations
Designated as hedges under accounting guidance:			
Crude oil futures contracts (fair value hedge)	Volatility in crude oil prices - effect on market value of inventory	Derivative is recorded in Other current assets (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventories	Excess, if any, over effective portion of hedge is recorded in Onshore facilities and transportation costs - product costs Effective portion is offset in cost of sales against change in value of inventory being hedged
Not qualifying or not designated as hedges under accounting guidance:			
Commodity hedges consisting of crude oil, heating oil and natural gas futures, forward contracts, swaps and call options	Volatility in crude oil, natural gas and petroleum products prices - effect on market value of inventory or purchase commitments	Derivative is recorded in Other current assets (offset against margin deposits) or Accrued liabilities	Entire amount of change in fair value of derivative is recorded in Onshore facilities and transportation costs - product costs and Sodium minerals and sulfur services - operating costs
Preferred Distribution Rate Reset Election	This instrument is not related to a risk, but is rather part of a host contract with the issuance of our Preferred Units	Derivative is recorded in Other long-term liabilities	Entire amount of change in fair value of derivative is recorded in Other income (expense)

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 December 31, 2018 and 2017:

Fair Value of Derivative Assets and Liabilities

	Consolidated Balance Sheets Location	Fair Value December 31, 2018	December 31, 2017
Asset Derivatives:			
Commodity derivatives—futures and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$3,431	$ 505
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other	(1,361)	(505)
Net amount of assets presented in the Consolidated Balance Sheets		$2,070	$ —
Natural Gas Swap (undesignated hedge)	Current Assets - Other	1,274	—
Commodity derivatives—futures and call options (designated hedges):			
Gross amount of recognized assets	Current Assets - Other	$469	$ 54
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other	(44)	(54)
Net amount of assets presented in the Consolidated Balance Sheets		$425	$ —
Liability Derivatives:			
Preferred Distribution Rate Reset Election (2)	Other Long-Term Liabilities (2)	$(40,840)	$ (45,209)
Natural Gas Swap (undesignated hedge)	Current Liabilities - Accrued Liabilities	(125)	—
Commodity derivatives—futures and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(1,361)	$ (1,203)
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other (1)	1,361	1,203
Net amount of liabilities presented in the Consolidated Balance Sheets		$—	$ —
Commodity derivatives—futures and call options (designated hedges):			
Gross amount of recognized liabilities	Current Assets - Other (1)	$(44)	$ (863)
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other (1)	44	338
Net amount of liabilities presented in the Consolidated Balance Sheets		$—	$ (525)

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

(2) Refer to Note 12 and Note 20 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 December 31, 2018, we had a net broker receivable of approximately $2.2 million (consisting of initial margin

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of $3.1 million decreased by $0.9 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 December 31, 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 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 the preferred units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Consolidated Balance Sheet. Corresponding changes in fair value are recognized in Other Income (Expense) in our Consolidated Statement of Operations. At December 31, 2018, the fair value of this embedded derivative was a liability of $40.8 million. See Note 12 for additional information regarding our Class A convertible preferred units and the Rate Reset Election.

Effect on Operating Results

		Amount of Gain (Loss) Recognized in Income Year Ended December 31,		
	Consolidated Statements of Operations Location	2018	2017	2016
Commodity derivatives—futures and call options:				
Contracts designated as hedges under accounting guidance	Onshore facilities and transportation product costs	$(544)	$5,116	$(13,195)
Contracts not considered hedges under accounting guidance	Onshore facilities and transportation product costs, sodium minerals and sulfur services operating costs	3,914	(1,314)	(5,847)
Total commodity derivatives		$3,370	$3,802	$(19,042)
Natural Gas Swap	Sodium minerals and sulfur services operating costs	1,906	$—	$—
Preferred Distribution Rate Reset Election (Note 20)	Other Income (Expense)	$8,360	$(10,472)	$—

We have no derivative contracts with credit contingent features.

20. Fair-Value Measurements

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

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

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

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

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

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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 December 31, 2018 and 2017.

	December 31, 2018			December 31, 2017		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$3,900	$1,274	$—	$559	$ —	$—
Liabilities	$(1,405)	$(125)	$—	$(2,066)	$ —	$—
Preferred Distribution Rate Reset Election	$—	$—	$(40,840)	$—	$ —	$(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:

Balance as of December 31, 2016	—
Initial valuation of Preferred Distribution Rate Reset Election	(34,450)
Net Loss for the period including earnings	(10,472)
Allocation of Distribution Paid-in-kind	(287)
Balance as of December 31, 2017	(45,209)
Net gain for the period included in earnings	8,360
Allocation of Distribution Paid-in-kind	(3,991)
Balance as of December 31, 2018	$(40,840)

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 December 31, 2018.
The fair value of embedded derivative feature is based on a valuation model that estimates the fair value of the convertible preferred units with and without a Rate Reset Election. This model contains inputs, including our common unit price, a ten year history of the dividend yield, default probabilities and timing estimates which involve management judgment. A significant increase or decrease in the value of these inputs could result in a material change in fair value to this embedded derivative feature. We report unrealized gains and losses associated with this embedded derivative in our Consolidated Statements of Operations as Other income (expense), net.
See Note 19 for additional information on our derivative instruments.
Nonfinancial Assets and Liabilities
We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified in Level 3, in the event that we were required to measure and record such assets within our Consolidated Financial Statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified in Level 3.

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 December 31, 2018 our

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senior unsecured notes had a carrying value of $2.5 billion and a fair value of $2.3 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.

21. Employee Benefit Plans

Upon acquisition of our Alkali Business in 2017, we now sponsor a defined benefit plan. We account for the Alkali Business benefit plan as a single employer pension plan that benefits only employees of our Alkali Business, and thus, the related assets and liability costs of the plan are recorded in the Consolidated Balance Sheet. Under the Alkali Business benefit plan, each eligible employee will automatically become a participant upon completion of one year of credited service. Retirement benefits under this plan are calculated based on the total years of service of an eligible participant, multiplied by a specified benefit rate in effect at the termination of the plan participant's years of service.

The change in benefit obligations, plan assets and funded status along with amounts recognized in the Consolidated Balance Sheet are as follows:

	December 31,	
	2018	2017
Change in benefit obligation:		
Benefit Obligation, beginning of year	$22,530	$—
Service Cost	5,153	1,749
Interest Cost	862	267
Actuarial (Gain) Loss	(3,816)	992
Benefits Paid	(218)	(56)
Acquisition of Alkali Business	—	19,578
Benefit Obligation, end of year	24,511	22,530
Change in plan assets:		
Fair Value of Plan Assets, beginning of year	13,306	—
Actual Return (loss) on Plan Assets	(1,300)	647
Employer Contributions	3,928	2,250
Benefits Paid	(218)	(56)
Acquisition of Alkali Business	—	10,465
Fair Value of Plan assets, end of year	15,716	13,306
Funded Status at end of period	$(8,795)	$(9,224)
Amounts recognized in the Consolidated Balance Sheet:		
Non-current assets	$—	$—
Current liabilities	—	—
Non-current Liabilities	(8,795)	(9,224)
Net Liability at end of year	$(8,795)	$(9,224)
Amounts recognized in accumulated other comprehensive income (loss):		
Net actuarial (gain) loss	(939)	604
Amounts recognized in accumulated other comprehensive income (loss:)	$(939)	$604

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Estimated Future Cash Flows- The following employer contributions and benefit payments, which reflect expected future service, are expected to be paid as follows:

Employer Contributions	
Expected 2019 Contributions by Employer	$3,550
Future Expected Benefit Payments	
2019	$587
2020	816
2021	962
2022	1,109
2023	1,265
2024-2028	8,465

Net Periodic Pension Costs- The components of net periodic pension costs for the Alkali benefit plan are as follows:

	December 31,	
	2018	2017
Service Cost	$5,153	$1,749
Interest Cost	862	267
Expected Return on Assets	(973)	(259)
	$5,042	$1,757

Significant Assumptions- Discount rates are determined annually and are based on rates of return of high-quality long-term fixed income securities currently available and expected to be available during the maturity of the pension benefits.

The long-term rate of return estimation for the Alkali benefit plan is based on a capital asset pricing model using historical data and a forecasted earnings model. An expected return on plan assets analysis is performed which incorporates the current portfolio allocation, historical asset-class returns and an assessment of expected future performance using asset-class risk factors.

The Alkali Business benefit plan is administered by a Board-appointed committee that has fiduciary responsibility for the plan's management. The committee is responsible for the oversight and management of the plan's investments. The committee maintains an investment policy that provides guidelines for selection and retention of investment managers or funds, allocation of plan assets and performance review procedures and updating of the policy. The objective of the committee's investment policy is to manage the plan assets in such a way that will allow for the on-going payment of the Company's obligation to the beneficiaries.

Weighted average assumptions used to determine benefit obligation:	December 31, 2018	December 31, 2017
Discount Rate	4.62 %	3.90 %
Expected Long-term Rate of Return	6.41 %	6.28 %
Rate of Compensation Increase	N/A	N/A

The discount rate used to determine the net periodic cost at the beginning of the period was 3.90%.

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Pension Plan Assets - We maintain target allocation percentages among various asset classes based on an investment policy established for our Pension Plan. The target allocation is designed to achieve long term objectives of return, mitigating risk, and considering expected cash flows. Our Pension Plan asset allocations at December 31, 2018 by asset category are as follows:

December 31, 2018

	Target %	Actual %
Equity securities	41-60%	51 %
Fixed income securities	40-50%	41 %
Other	0-10%	8 %

A summary of total investments for our pension plan assets measured at fair value is presented as of December 31 for the periods below:

	2018 Level 1	Level 2	Level 3	Total	2017 Level 1	Level 2	Level 3	Total
Cash and cash equivalents	506	—	—	$506	260	—	—	$260
Equity securities	8,038	—	—	$8,038	2,518	—	—	$2,518
Mutual and other exchange traded funds	7,172	—	—	$7,172	10,528	—	—	$10,528
	15,716	—	—	$15,716	13,306	—	—	$13,306

22. Commitments and Contingencies

Commitments and Guarantees

Our office lease for our corporate headquarters extends until October 31, 2022. To transport products, we lease tractors, trailers and railcars. In addition, we lease tanks and terminals for the storage of crude oil, petroleum products, NaHS and caustic soda. Additionally, we lease a segment of pipeline where under the terms we make payments based on throughput. We have no minimum volumetric or financial requirements remaining on our pipeline lease.

The future minimum rental payments under all non-cancelable operating leases as of December 31, 2018, were as follows (in thousands):

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2019	$4,197	$ 27,547	$ 14,298	$46,042
2020	4,119	24,642	10,594	39,355
2021	3,298	19,536	7,840	30,674
2022	2,692	18,113	6,653	27,458
2023	961	17,290	9,378	27,629
2024 and thereafter	3,735	45,390	77,104	126,229
Total minimum lease obligations	$19,002	$ 152,518	$ 125,867	$297,387

Total operating lease expense from our continuing operations was as follows (in thousands):

Year Ended December 31, 2018	$30,798
Year Ended December 31, 2017	$36,933
Year Ended December 31, 2016	$41,906

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

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

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.

23. Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income taxes. Other than with respect to our corporate subsidiaries and the Texas Margin Tax, our taxable income or loss is includible in the federal income tax returns of each of our partners.

A few of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. We pay federal and state income taxes on these operations.

As a result of the Tax Cuts and Jobs Act enacted on December 22, 2017, The Partnership remeasured its U.S. deferred tax assets and liabilities during the year ended December 31, 2017 and recorded a $5.3 million benefit relating to the U.S. federal corporate tax rate change.

Our income tax (benefit) expense is as follows:

	Year Ended December 31,		
	2018	2017	2016
Current:			
Federal	$—	$—	$—
State	810	100	1,200
Total current income tax expense	$810	$100	$1,200
Deferred:			
Federal	$114	$(5,530)	$1,862
State	574	1,471	280
Total deferred income tax expense (benefit)	$688	$(4,059)	$2,142
Total income tax expense (benefit)	$1,498	$(3,959)	$3,342

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Deferred income taxes relate to temporary differences based on tax laws and statutory rates that were enacted at the balance sheet date. Deferred tax assets and liabilities consist of the following:

	December 31,	
	2018	2017
Deferred tax assets:		
Net operating loss carryforwards	$11,491	$9,506
Total long-term deferred tax asset	11,491	9,506
Valuation allowances	(1,758)	(1,285)
Total deferred tax assets	$9,733	$8,221
Deferred tax liabilities:		
Long-term:		
Fixed assets	$(2,893)	$(3,896)
Intangible assets	(18,209)	(15,797)
Other	(1,207)	(441)
Total long-term liability	(22,309)	(20,134)
Total deferred tax liabilities	$(22,309)	$(20,134)
Total net deferred tax liability	$(12,576)	$(11,913)

We record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets depends on the ability to generate sufficient taxable income of the appropriate character in the future and in the appropriate taxing jurisdictions.

The reconciliation between the Partnership's effective tax rate on income (loss) from operations and the statutory tax rate is as follows:

	Year Ended December 31,		
	2018	2017	2016
Income(loss) from operations before income taxes	$(10,294)	$78,120	$114,424
Partnership income not subject to federal income tax	10,824	(77,704)	(109,111)
Income subject to federal income taxes	$530	$416	$5,313
Tax expense at federal statutory rate	$111	$146	$1,860
State income taxes, net of federal tax	1,285	1,396	949
Return to provision, federal and state	(128)	(163)	(198)
Other	230	(68)	731
Re-measurement of deferred taxes due to enacted tax rate change	—	(5,270)	—
Income tax expense (benefit)	$1,498	$(3,959)	$3,342
Effective tax rate on income from operations before income taxes	(15)%	(5)%	3%

At December 31, 2018, 2017 and 2016, we had no uncertain tax positions.

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24. Quarterly Financial Data (Unaudited)

The table below summarizes our unaudited quarterly financial data for 2018 and 2017.

	2018 Quarters			
	First	Second	Third	Fourth
Revenues from continuing operations	$725,808	$752,388	$745,278	$689,296
Operating income	$59,081	$60,900	$46,148	$4,119
Net income (loss)	$7,898	$10,871	$(1,634)	$(28,927)
Net loss attributable to noncontrolling interest	$136	$126	$1,311	$4,144
Net income (loss) attributable to Genesis Energy, L.P.	$8,034	$10,997	$(323)	$(24,783)
Basic and diluted net income (loss) per common unit:				
Net income (loss) per common unit	$(0.07)	$(0.05)	$(0.15)	$(0.35)
Cash distributions per common unit (1)	$0.5200	$0.5300	$0.5400	$0.5500

	2017 Quarters			
	First	Second	Third	Fourth
Revenues from continuing operations	$415,491	$406,723	$486,114	$720,049
Operating income	$52,597	$61,447	$43,100	$63,407
Net income	$26,938	$33,580	$6,160	$15,401
Net loss attributable to noncontrolling interest	$152	$153	$152	$111
Net income attributable to Genesis Energy, L.P.	$27,090	$33,733	$6,312	$15,512
Basic and diluted net income (loss) per common unit:				
Net income (loss) per common unit	$0.23	$0.28	$0.01	$(0.01)
Cash distributions per common unit (1)	$0.7100	$0.7200	$0.7225	$0.5000

(1) Represents cash distributions declared and paid in the applicable period.

25. 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 11 for additional information regarding our consolidated debt obligations.

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The following is condensed consolidating financial information for Genesis Energy, L.P. and subsidiary guarantors:

Condensed Consolidating Balance Sheet
December 31, 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	$ —	$8,968	$ 1,326	$—	$10,300
Other current assets	50	—	419,809	13,285	(165)	432,979
Total current assets	56	—	428,777	14,611	(165)	443,279
Fixed Assets, at cost	—	—	5,363,274	77,584	—	5,440,858
Less: Accumulated depreciation	—	—	(994,609)	(29,216)	—	(1,023,825)
Net fixed assets	—	—	4,368,665	48,368	—	4,417,033
Mineral Leaseholds, net of accumulated depletion	—	—	560,481	—	—	560,481
Goodwill	—	—	301,959	—	—	301,959
Other assets, net of amortization	10,776	—	440,312	117,766	(167,620)	401,234
Advances to affiliates	3,305,568	—	—	103,061	(3,408,629)	—
Equity investees	—	—	355,085	—	—	355,085
Investments in subsidiaries	2,648,510	—	60,532	—	(2,709,042)	—
Total assets	$5,964,910	$ —	$6,515,811	$ 283,806	$(6,285,456)	$6,479,071
LIABILITIES AND CAPITAL						
Current liabilities	$39,342	$ —	$266,252	$ 27,350	$(110)	$332,834
Senior secured credit facility	970,100	—	—	—	—	970,100
Senior unsecured notes, net of debt issuance costs	2,462,363	—	—	—	—	2,462,363
Deferred tax liabilities	—	—	12,576	—	—	12,576
Advances from affiliates	—	—	3,408,659	—	(3,408,659)	—
Other liabilities	40,840	—	188,181	197,658	(167,481)	259,198
Total liabilities	3,512,645	—	3,875,668	225,008	(3,576,250)	4,037,071
Mezzanine Capital:						
Class A Convertible Preferred Units	761,466	—	—	—	—	761,466
Partners' capital, common units	1,690,799	—	2,639,204	70,002	(2,709,206)	1,690,799
Accumulated other comprehensive income (loss)[1]	—	—	939	—	—	939
Noncontrolling interests	—	—	—	(11,204)	—	(11,204)
Total liabilities, mezzanine capital and partners' capital	$5,964,910	$ —	$6,515,811	$ 283,806	$(6,285,456)	$6,479,071

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

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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, net of accumulated depletion	—	—	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	—	—	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 facility	1,099,200	—	—	—	—	1,099,200
Senior unsecured notes, net of debt issuance costs	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	2,026,147	—	2,683,506	89,026	(2,772,532)	2,026,147
Accumulated other comprehensive income (loss)	—	—	(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

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Condensed Consolidating Statement of Operations
Year Ended December 31, 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	$ —	$ —	$ 284,544	$ —	$ —	$ 284,544
Sodium minerals and sulfur services	—	—	1,171,913	11,113	(8,592)	1,174,434
Marine transportation	—	—	219,937	—	—	219,937
Onshore facilities and transportation	—	—	1,214,235	19,620	—	1,233,855
Total revenues	—	—	2,890,629	30,733	(8,592)	2,912,770
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	1,125,528	1,202	—	1,126,730
Marine transportation operating costs	—	—	172,527	—	—	172,527
Sodium minerals and sulfur services operating costs	—	—	911,135	9,948	(8,592)	912,491
Offshore pipeline transportation operating costs	—	—	64,272	2,396	—	66,668
General and administrative	—	—	66,898	—	—	66,898
Depreciation, depletion and amortization	—	—	310,690	2,500	—	313,190
Gain on sale of assets	—	—	(42,264)	—	—	(42,264)
Impairment expense	—	—	100,093	26,189	—	126,282
Total costs and expenses	—	—	2,708,879	42,235	(8,592)	2,742,522
OPERATING INCOME	—	—	181,750	(11,502)	—	170,248
Equity in earnings of equity investees	—	—	43,626	—	—	43,626
Equity in earnings of subsidiaries	219,615	—	(18,564)	—	(201,051)	—
Interest expense, net	(230,713)	—	14,706	(13,184)	—	(229,191)
Other income	5,023	—	—	—	—	5,023
Income before income taxes	(6,075)	—	221,518	(24,686)	(201,051)	(10,294)
Income tax benefit (expense)	—	—	(1,727)	229	—	(1,498)
NET INCOME (LOSS)	(6,075)	—	219,791	(24,457)	(201,051)	(11,792)
Net loss attributable to noncontrolling interests	—	—	—	5,717	—	5,717
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ (6,075)	$ —	$ 219,791	$ (18,740)	$ (201,051)	$ (6,075)
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(69,801)	—	—	—	—	(69,801)
NET INCOME (LOSS) AVAILABLE TO COMMON UNIT HOLDERS	$ (75,876)	$ —	$ 219,791	$ (18,740)	$ (201,051)	$ (75,876)

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Condensed Consolidating Statement of Operations
Year Ended 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
REVENUES:						
Offshore pipeline transportation services	$ —	$ —	$ 318,239		$ —	$ 318,239
Sodium minerals and sulfur services	—	—	460,790	9,252	(7,420)	462,622
Marine transportation	—	—	205,287	—	—	205,287
Onshore facilities and transportation	—	—	1,023,293	18,936	—	1,042,229
Total revenues	—	—	2,007,609	28,188	(7,420)	2,028,377
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	967,558	1,089	—	968,647
Marine transportation operating costs	—	—	154,606	—	—	154,606
Sodium minerals and sulfur services operating costs	—	—	332,209	9,129	(7,420)	333,918
Offshore pipeline transportation operating costs	—	—	69,225	2,840	—	72,065
General and administrative	—	—	66,421	—	—	66,421
Depreciation, depletion and amortization	—	—	249,980	2,500	—	252,480
Gain on sale of assets	—	—	(40,311)	—	—	(40,311)
Total costs and expenses	—	—	1,799,688	15,558	(7,420)	1,807,826
OPERATING INCOME	—	—	207,921	12,630	—	220,551
Equity in earnings of equity investees	—	—	51,046	—	—	51,046
Equity in earnings of subsidiaries	276,341	—	(520)	—	(275,821)	—
Interest expense, net	(176,979)	—	14,122	(13,905)	—	(176,762)
Other expense	(16,715)	—	—	—	—	(16,715)
Income before income taxes	82,647	—	272,569	(1,275)	(275,821)	78,120
Income tax expense	—	—	3,928	31	—	3,959
NET INCOME	82,647	—	276,497	(1,244)	(275,821)	82,079
Net loss attributable to noncontrolling interests	—	—	—	568	—	568
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 82,647	$ —	$ 276,497	$ (676)	$ (275,821)	$ 82,647
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(21,995)	—	—	—	—	(21,995)
NET INCOME AVAILABLE TO COMMON UNIT HOLDERS	$ 60,652	$ —	$ 276,497	$ (676)	$ (275,821)	$ 60,652

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Condensed Consolidating Statement of Operations
Year Ended December 31, 2016

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Offshore pipeline transportation services	$ —	$ —	$ 334,679		$ —	$ 334,679
Sodium minerals and sulfur services	—	—	171,389	7,873	(7,759)	171,503
Marine transportation	—	—	213,021	—	—	213,021
Onshore facilities and transportation	—	—	972,794	20,496	—	993,290
Total revenues	—	—	1,691,883	28,369	(7,759)	1,712,493
COSTS AND EXPENSES:						
Onshore facilities and transportation costs	—	—	923,567	1,060	—	924,627
Marine transportation operating costs	—	—	142,551	—	—	142,551
Sodium minerals and sulfur services operating costs	—	—	90,711	8,491	(7,759)	91,443
Offshore pipeline transportation operating costs	—	—	68,791	10,833	—	79,624
General and administrative	—	—	45,625	—	—	45,625
Depreciation and amortization	—	—	219,696	2,500	—	222,196
Total costs and expenses	—	—	1,490,941	22,884	(7,759)	1,506,066
OPERATING INCOME	—	—	200,942	5,485	—	206,427
Equity in earnings of equity investees	—	—	47,944	—	—	47,944
Equity in earnings of subsidiaries	253,048	—	(6,744)	—	(246,304)	—
Interest expense, net	(139,799)	—	14,407	(14,555)	—	(139,947)
Income before income taxes	113,249	—	256,549	(9,070)	(246,304)	114,424
Income tax expense	—	—	(3,337)	(5)	—	(3,342)
NET INCOME	$ 113,249	$ —	$ 253,212	$ (9,075)	$ (246,304)	$ 111,082
Net loss attributable to noncontrolling interest	$ —	$ —	$ —	$ 2,167	$ —	2,167
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 113,249	$ —	$ 253,212	$ (6,908)	$ (246,304)	$ 113,249
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	$ —	$ —	$ —	$ —	$ —	—
NET INCOME AVAILABLE TO COMMON UNIT HOLDERS	$ 113,249	$ —	$ 253,212	$ (6,908)	$ (246,304)	$ 113,249

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Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 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 (used in) provided by operating activities	$ 28,784	$ —	$ 595,510	$ 2,556	$ (236,811)	$ 390,039
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(195,367)	—	—	(195,367)
Cash distributions received from equity investees - return of investment	—	—	28,979	—	—	28,979
Investments in equity investees	—	—	(3,018)	—	—	(3,018)
Intercompany transfers	503,144	—	—	—	(503,144)	—
Repayments on loan to non-guarantor subsidiary	—	—	7,484	—	(7,484)	—
Proceeds from asset sales	—	—	310,099	—	—	310,099
Net cash provided by (used in) provided by investing activities	503,144	—	148,177	—	(510,628)	140,693
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	980,700	—	—	—	—	980,700
Repayments on senior secured credit facility	(1,109,800)	—	—	—	—	(1,109,800)
Repayment of senior unsecured notes	(145,170)	—	—	—	—	(145,170)
Debt issuance costs	(242)	—	—	—	—	(242)
Intercompany transfers	—	—	(485,506)	(17,638)	503,144	—
Distributions to partners/owners	(257,416)	—	(257,416)	—	257,416	(257,416)
Contributions from noncontrolling interest	—	—	—	2,592	—	2,592
Other, net	—	—	(137)	13,121	(13,121)	(137)
Net cash provided by (used in) financing activities	(531,928)	—	(743,059)	(1,925)	747,439	(529,473)
Net increase in cash and cash equivalents	—	—	628	631	—	1,259
Cash and cash equivalents at beginning of period	6	—	8,340	695	—	9,041
Cash and cash equivalents at end of period	$ 6	$ —	$ 8,968	$ 1,326	$ —	$ 10,300

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Condensed Consolidating Statement of Cash Flows
Year Ended 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
Net cash (used in) provided by operating activities	$ 162,980	$ —	$ 466,425	$ (4,585)	$ (301,264)	$ 323,556
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(250,593)	—	—	(250,593)
Cash distributions received from equity investees - return of investment	—	—	35,582	—	—	35,582
Investments in equity investees	(140,513)	—	(4,647)	—	140,513	(4,647)
Acquisitions	—	—	(1,325,759)	—	—	(1,325,759)
Intercompany transfers	(1,157,781)	—	—	—	1,157,781	—
Repayments on loan to non-guarantor subsidiary	—	—	6,764	—	(6,764)	—
Contributions in aid of construction costs	—	—	124	—	—	124
Proceeds from assets sales	—	—	85,722	—	—	85,722
Net cash (used in) provided by investing activities	(1,298,294)	—	(1,452,807)	—	1,291,530	(1,459,571)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,458,700	—	—	—	—	1,458,700
Repayments on senior secured credit facility	(1,637,700)	—	—	—	—	(1,637,700)
Proceeds from issuance of senior unsecured notes, including premium	1,000,000	—	—	—	—	1,000,000
Proceeds from issuance of Series A convertible preferred	726,419	—	—	—	—	726,419
Repayment of senior unsecured notes	(204,830)	—	—	—	—	(204,830)
Debt issuance costs	(25,913)	—	—	—	—	(25,913)
Intercompany transfers	—	—	1,169,781	(12,000)	(1,157,781)	—
Issuance of common units for cash, net	140,513	—	140,513	—	(140,513)	140,513
Distributions to partners/owners	(321,875)	—	(321,875)	—	321,875	(321,875)
Contributions from noncontrolling interest	—	—	—	2,770	—	2,770
Other, net	—	—	(57)	13,847	(13,847)	(57)
Net cash provided by (used in) financing activities	1,135,314	—	988,362	4,617	(990,266)	1,138,027
Net increase in cash and cash equivalents	—	—	1,980	32	—	2,012
Cash and cash equivalents at beginning of period	6	—	6,360	663	—	7,029
Cash and cash equivalents at end of period	$ 6	$ —	$ 8,340	$ 695	$ —	$ 9,041

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Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2016

	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$179,853	$ —	$382,734	$ 9,586	$(289,421)	$282,752
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(463,100)	—	—	(463,100)
Cash distributions received from equity investees - return of investment	—	—	36,939	—	—	36,939
Investments in equity investees	(298,020)	—	—	—	298,020	—
Acquisitions	—	—	(25,394)	—	—	(25,394)
Intercompany transfers	(31,436)	—	—	—	31,436	—
Repayments on loan to non-guarantor subsidiary	—	—	6,113	—	(6,113)	—
Contributions in aid of construction costs	—	—	13,374	—	—	13,374
Proceeds from asset sales	—	—	3,609	—	—	3,609
Other, net	—	—	(151)	—	—	(151)
Net cash (used in) provided by investing activities	(329,456)	—	(428,610)	—	323,343	(434,723)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,115,800	—	—	—	—	1,115,800
Repayments on senior secured credit facility	(952,600)	—	—	—	—	(952,600)
Debt issuance costs	(1,578)	—	—	—	—	(1,578)
Distribution to partners/owners	(310,039)	—	(310,039)	—	310,039	(310,039)
Contributions from noncontrolling interest	—	—	—	236	—	236
Issuance of common units for cash, net	298,020	—	298,020	—	(298,020)	298,020
Intercompany transfers	—	—	57,701	(26,264)	(31,437)	—
Other, net	—	—	(1,734)	14,504	(14,504)	(1,734)
Net cash provided by (used in) financing activities	149,603	—	43,948	(11,524)	(33,922)	148,105
Net decrease in cash and cash equivalents	—	—	(1,928)	(1,938)	—	(3,866)
Cash and cash equivalents at beginning of period	6	—	8,288	2,601	—	10,895
Cash and cash equivalents at end of period	$6	$ —	$6,360	$ 663	$—	$7,029

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Report of Independent Auditors

The Management Committee
Poseidon Oil Pipeline Company, L.L.C.

We have audited the accompanying financial statements of Poseidon Oil Pipeline Company, L.L.C. which comprise the balance sheets as of December 31, 2018 and 2017, and the related statements of operations, cash flows, and members' equity (deficit) for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C. at December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Houston, Texas
February 19, 2019

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INDEPENDENT AUDITORS' REPORT

To the Management Committee of
Poseidon Oil Pipeline Company, L.L.C.
Houston, Texas

We have audited the accompanying statements of operations, cash flows, and members' equity of Poseidon Oil Pipeline Company, L.L.C. (the "Company") for the year ended December 31, 2016, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Poseidon Oil Pipeline Company, L.L.C. for the year ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 17, 2017

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POSEIDON OIL PIPELINE COMPANY, L.L.C.
BALANCE SHEETS
(In thousands)

	December 31, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$261	$132
Accounts receivable—trade	15,578	14,443
Accounts receivable—related parties	1,189	1,121
Crude oil inventory	1,565	2,691
Other current assets	318	324
Total current assets	18,911	18,711
FIXED ASSETS, net	202,116	217,343
OTHER ASSETS	886	1,203
TOTAL ASSETS	$221,913	$237,257
LIABILITIES AND MEMBERS’ EQUITY		
CURRENT LIABILITIES:		
Accounts payable – trade	$2,548	$1,757
Accounts payable – related parties	2,664	2,384
Deferred revenue	9,187	11,357
Other current liabilities	1,510	2,062
Total current liabilities	15,909	17,560
LONG-TERM DEBT	208,300	206,600
OTHER LIABILITIES	34,581	30,834
MEMBERS' EQUITY (DEFICIT)	(36,877)	(17,737)
TOTAL LIABILITIES AND MEMBERS' EQUITY	$221,913	$237,257

The accompanying notes are an integral part of these financial statements.

POSEIDON OIL PIPELINE COMPANY, L.L.C.
STATEMENTS OF OPERATIONS
(In thousands, except per unit amounts)

	Year Ended December 31,		
	2018	2017	2016
CRUDE OIL HANDLING REVENUES:			
Third parties	$99,356	$98,024	$100,383
Related parties	16,139	19,109	19,899
Total crude oil handling revenues	115,495	117,133	120,282
COSTS AND EXPENSES:			
Crude oil handling costs			
Third parties	2,470	1,774	1,989
Related parties	6,345	5,889	3,788
Total crude oil handling costs	8,815	7,663	5,777
Other operating costs and expenses			
Third parties	823	852	1,238
Related parties	8,640	8,388	7,914
Total other operating costs and expenses	9,463	9,240	9,152
Depreciation and accretion expenses	16,218	15,633	15,615
General and administrative costs	65	45	101
Total costs and expenses	34,561	32,581	30,645
OPERATING INCOME	80,934	84,552	89,637
Interest expense	7,974	6,026	4,729
NET INCOME	$72,960	$78,526	$84,908

The accompanying notes are an integral part of these financial statements.

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POSEIDON OIL PIPELINE COMPANY, L.L.C.
STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$72,960	$78,526	$84,908
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and accretion expenses	16,490	15,905	15,887
Effect of changes in operating accounts:			
Accounts receivable	(1,203)	(687)	2,139
Inventories	1,201	(1,230)	(887)
Other current assets	51	(261)	(379)
Accounts payable	1,062	(1,434)	409
Other liabilities	332	11,334	9,082
Net cash provided by operating activities	90,893	102,153	111,159
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to fixed assets	(364)	(66)	(183)
Net cash used in investing activities	(364)	(66)	(183)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under revolving credit facility	71,900	84,200	85,900
Repayments of principal	(70,200)	(79,650)	(81,100)
Cash distributions to Members	(92,100)	(106,600)	(116,300)
Net cash used in financing activities	(90,400)	(102,050)	(111,500)
Net increase (decrease) in cash and cash equivalents	129	37	(524)
Cash and cash equivalents at beginning of period	132	95	619
Cash and cash equivalents at end of period	$261	$132	$95
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash paid during the year for interest	$7,544	$5,698	$4,402
Current liabilities for capital expenditures at end of year	$10	$57	$—

The accompanying notes are an integral part of these financial statements.

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POSEIDON OIL PIPELINE COMPANY, L.L.C.
STATEMENT OF MEMBERS' EQUITY (DEFICIT)
(In thousands)

	Poseidon Pipeline Company, L.L.C.	Shell Midstream Partners, L.P.	GEL Poseidon, LLC	Total
January 1, 2016	15,022	$ 15,022	$ 11,685	$ 41,729
Net income	30,567	30,567	23,774	$ 84,908
Cash distributions to members	(41,868)	(41,868)	(32,564)	$ (116,300)
December 31, 2016	3,721	3,721	2,895	10,337
Net income	28,269	28,269	21,988	$ 78,526
Cash distributions to members	(38,376)	(38,376)	(29,848)	$ (106,600)
December 31, 2017	(6,386)	(6,386)	(4,965)	(17,737)
Net income	26,266	26,266	20,428	$ 72,960
Cash distributions to members	(33,156)	(33,156)	(25,788)	$ (92,100)
December 31, 2018	$ (13,276)	$ (13,276)	$ (10,325)	$ (36,877)

The accompanying notes are an integral part of these financial statements.

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POSEIDON OIL PIPELINE COMPANY, L.L.C.
NOTES TO FINANCIAL STATEMENTS

Note 1. Company Organization and Description of Business

Company Organization
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”) is a Delaware limited liability company formed in February 1996 to design, construct, own and operate an unregulated crude oil pipeline system located in the central Gulf of Mexico offshore Louisiana. Unless the context requires otherwise, references to “we”, “us”, “our” or “the Company” within these notes are intended to mean Poseidon.

At December 31, 2018, we were owned (i) 36% by Poseidon Pipeline Company, L.L.C. and (ii) 28% by GEL Poseidon, LLC, collectively ("Genesis") and (iii) 36% by Shell Midstream Partners, L.P. (“Shell”).

Description of Business
The Poseidon Oil Pipeline System (the “Pipeline”) gathers crude oil production from the outer continental shelf and deep-water areas of the Gulf of Mexico offshore Louisiana for delivery to onshore locations in south Louisiana. The system includes a pipeline junction platform located at South Marsh Island 205 (“SMI-205”). Manta Ray Gathering Company, L.L.C. (“Manta Ray”), a wholly owned subsidiary of Genesis acquired as part of Enterprise’s offshore business, serves as operator of the Pipeline.

Note 2. Significant Accounting Policies

Our financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles (“GAAP”).

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

In preparing these financial statements, the Company has evaluated subsequent events for potential recognition or disclosure through February 19, 2019, the issuance date of the financial statements.

Cash and Cash Equivalents
Cash and cash equivalents represent unrestricted cash on hand and may also include highly liquid investments with original maturities of less than three months from the date of purchase.

Accounts Receivable
We review our outstanding accounts receivable balances on a regular basis and record an allowance for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

Contingency and Liability Accruals
We accrue reserves for contingent liabilities including environmental remediation and potential legal claims. When our assessment indicates that it is probable that a liability has occurred and the amount of the liability can be reasonably estimated, we make accruals. We base our estimates on all known facts at the time and our assessment of the ultimate outcome, including consultation with external experts and counsel. We revise these estimates as additional information is obtained or resolution is achieved.

We also make estimates related to future payments for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include costs for studies and testing as well as remediation and restoration. We sometimes make these estimates with the assistance of third parties involved in monitoring the remediation effort.

At December 31, 2018, we were not aware of any contingencies or liabilities that would have a material effect on our financial position, results of operations or cash flows.

Crude Oil Handling Costs
Crude oil handling costs represent expenses we incur as a result of utilizing third party-owned and related party-owned pipelines in the provision of services.

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Estimates
Preparing our financial statements in conformity with GAAP requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation methods used for fixed assets; (ii) measurement of fair value and projections used in impairment testing of fixed assets; (iii) contingencies; (iv) revenue and expense accruals; and (v) estimates of future asset retirement obligations.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our financial statements.

Fair Value Information
The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair values based on their short-term nature. The fair value of the amounts outstanding under the February 2015 Credit Facility approximate book value as of December 31, 2018 given the variable rate nature of this debt.

Impairment Testing for Long-Lived Assets
Long-lived assets such as fixed assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset’s carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset’s carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques.

No asset impairment charges were recognized during the years ended December 31, 2018, 2017 or 2016.

Income Taxes
We are organized as a pass-through entity for federal income tax purposes. As a result, our financial statements do not provide for such taxes and our Members are individually responsible for their allocable share of our taxable income for federal income tax purposes.

Inventories
We take title to crude oil volumes we purchase from producers and volumes we obtain through contractual pipeline loss allowances. Timing and measurement differences between receipt and delivery volumes, as well as fluctuations in crude oil pricing, impact our inventory balances. Our inventory amounts are presented at the lower of average cost or market.

Due to fluctuating crude oil prices, we recognize lower of cost or market adjustments when the carrying value of our crude oil inventory exceeds its net realizable value. These non-cash charges are a component of “Crude oil handling costs” on our Statement of Operations in the period they are recognized. We recognized $0.1 million, $0.1 million and $0.0 million of lower of cost or net realizable value adjustments during 2018, 2017 and 2016, respectively.

Fixed Assets and Asset Retirement Obligations
Fixed assets are recorded at cost. Expenditures for additions, improvements and other enhancements to fixed assets are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When fixed assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of

operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the reporting periods it benefits. Our fixed assets are depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. Estimated useful lives are 5 to 30 years for our related fixed assets.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. ARO amounts are measured at their estimated fair value using expected present value techniques. Over time, the liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-

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term asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts. See Note 3 for additional information regarding our fixed assets and related AROs.

Revenue Recognition

Crude oil handling revenues are generated from purchase and sale agreements whereby we purchase crude oil from producers at various receipt points along the Pipeline for a contractual fixed price (less a “handling fee”) and sell common stream crude oil back to the producers at various redelivery points at the same contractual fixed price (before the handling fee was applied). Since these purchase and sale transactions are with the same customer and entered into in contemplation of one another, the purchase and sales amounts are netted against one another and the residual handling fees are recognized as crude oil handling revenue. The intent of these buy-sell arrangements is to earn a fee for handling crude oil (a service to the producer) and not to engage in crude oil marketing activities. We also net the corresponding receivables and payables from such transactions on our Balance Sheets for consistency of presentation.

We have entered into long-term pipeline capacity reservation agreements with Anadarko Petroleum Corporation, Eni Petroleum Co. Inc., Exxon Mobil Corporation, Freeport-McMoran Inc., Petrobras America Inc., and Teikoku Oil (North America) Co., Ltd., collectively the “Lucius producers”. The term of these agreements is 20 years (July 2014 through June 2034), which corresponds to the period of dedicated production from the Lucius producers under the agreements. The amount of pipeline capacity reserved each year for the Lucius producers is based on their expected production volumes for that period (as defined in the contract). The capacity reservation agreements require the Lucius producers to make scheduled minimum bill payments to us (as defined in the contract). We defer that portion of the minimum bill payments that relate to future performance obligations under the contract. We recognized $10.8 million, $13.3 million and $13.3 million of pipeline capacity reservation revenues from the Lucius producers for the years ended December 31, 2018, 2017, and 2016, respectively. At December 31, 2018 our deferred revenue attributable to the Lucius agreements totaled $41.1 million of which $9.2 million is expected to be recognized as revenue in 2019.

Recent and Proposed Accounting Pronouncements

In May 2014, the FASB issued revised guidance on revenue from contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard provides a five-step analysis for transactions to determine when and how revenue is recognized. The guidance permits the use of either a full retrospective or a modified retrospective approach. In July 2015, the FASB approved a one year deferral of the effective date of this standard to December 15, 2017 for annual reporting periods beginning after that date for public companies, or December 15, 2018 for all other entities. We have elected to adopt the new standard for the annual reporting period following December 15, 2018. We will adopt this guidance as of January 1, 2019 using the modified retrospective approach and will not have a material cumulative adjustment as a result of the adoption.

In February 2016, the FASB issued guidance to improve the transparency and comparability among companies by requiring lessees to recognize a lease liability and a corresponding lease asset for virtually all lease contracts. The guidance also requires additional disclosure about leasing arrangements. The guidance is effective for interim and annual periods beginning after December 15, 2018 for public entities and December 15, 2019 for non-public entities. We have elected to adopt the new standard for the annual reporting period following December 15, 2019. We are currently evaluating the impacts of our pending adoption of this guidance.

In August 2016, the FASB issued guidance that addresses how certain cash receipts and payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash flow, and other Topics. The guidance 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 with no material impact on our financial statements.

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Note 3. Fixed Assets and Asset Retirement Obligations

Fixed Assets
Our fixed asset values and related accumulated depreciation balances were as follows at the dates indicated:

	At December 31,		
	2018	2017	2016
Pipelines and facilities	$433,560	$433,174	$433,105
Construction in progress	—	87	32
Total	433,560	433,261	433,137
Less accumulated depreciation	(231,444)	(215,918)	(200,401)
Fixed assets, net	$202,116	$217,343	$232,736

Depreciation expense was $16.9 million, $15.5 million and $15.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Asset retirement obligations
Our AROs result from regulatory requirements that would be triggered by the retirement of our offshore pipeline and platform assets. During the third quarter of 2018, we began the abandonment of the ST-204 8” pipeline lateral, which is a part of the Poseidon Oil Pipeline system, after being notified that the owner of the ST-204 platform complex would be removing their assets from the production area. Due to this we revised the timing of the expected retirement obligation as it relates to the ST-204 lateral pipeline. During the fourth quarter of 2018, the abandonment of the ST-204 8” pipeline lateral was completed. No other revisions to the estimated retirement obligation were made during the period. The following table presents information regarding our estimable asset retirement liabilities for the periods noted.

	For the Year Ended December 31,		
	2018	2017	2016
ARO liability, beginning of period	$1,629	$1,513	$1,405
Liabilities settled	(604)	—	—
Accretion expense	127	116	108
Revisions in expected cash flows	1,341	—	—
Gain on settlement	(775)	—	—
ARO liability, end of period	$1,718	$1,629	$1,513

The ARO liability is included in "Other liabilities" in our December 31, 2018 and December 31, 2017 Balance Sheet. Cash settlements of the ARO obligation are recorded in "Other Liabilities" within the Operating Activities in the Statements of Cash Flows.

At December 31, 2018, our forecast of accretion expense is as follows for the next five years:

2019	2020	2021	2022	2023
$133	$143	$154	$166	$179

Note 4. Debt Obligation

February 2015 Credit Facility

In February 2015, we entered into an amended and restated revolving credit agreement having an initial borrowing capacity of $225 million, with a provision that its borrowing capacity could be expanded to $275 million with additional commitments from the lenders. Amounts borrowed under the February 2015 credit facility mature in February 2020. We used $186.8 million of borrowing capacity under the new credit facility to refinance principal amounts that were outstanding under the April 2011 Credit

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Facility at termination. We incurred $1.3 million of debt issuance costs related to the February 2015 Credit Facility of which $0.3 million and $0.6 million is deferred within other assets on our Balance Sheet at December 31, 2018 and 2017, respectively.

The weighted-average variable interest rate charged under the February 2015 credit facility was approximately 3.8% and 2.8% for the years ended December 31, 2018 and 2017, respectively. Interest rates charged under the 2015 credit facility are dependent on certain quarterly financial ratios (as defined in the credit agreement). For Eurodollar loans where our leverage ratio is greater than or equal to 1:1 and less than 2:1, the interest rate is the London Interbank Offered Rate ("LIBOR") plus 1.75%, and for Base Rate loans (as defined in the credit agreement), the interest rate is 0.75% plus a variable base rate equal to the greater of (i) the prime rate, (ii) the federal funds rate plus 0.50% or (iii) LIBOR plus 1.00%. The interest rate on Eurodollar and Base Rate loans would increase by 0.25% if our leverage ratio increased to greater than 2:1 and would decrease by 0.25% if our leverage ratio decreased to less than or equal to 1:1. In addition, we pay commitment fees on the unused portion of the revolving credit facility at rates that vary from 0.25% to 0.375%.

The February 2015 credit facility is non-recourse to our Members and secured by our assets. The February 2015 credit facility also contains customary covenants such as restrictions on debt levels, liens, guarantees, mergers, sale of assets and distributions to Members. A breach of any of these covenants could result in acceleration of our debt financial obligations. We were in compliance with the covenants of our credit facility at December 31, 2018.

In general, if an Event of Loss occurs (as defined in the credit agreement), we are obligated to either repair the damage or use any insurance proceeds we receive to reduce debt principal outstanding.

Note 5. Members' Equity

As a limited liability company, our Members are not personally liable for any of our debts, obligations or other liabilities. Income or loss amounts are allocated to Members based on their respective membership interests. Cash contributions by and distributions to Members are also based on their respective membership interests.

Cash distributions to Members are determined by our Management Committee, which is responsible for conducting the Company's affairs in accordance with our limited liability agreement.

Note 6. Related Party Transactions

The following table summarizes our related party transactions for the period indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Crude oil handling revenues:			
Genesis affiliates	994	986	1,007
Shell affiliates	15,145	18,123	18,892
Total	$16,139	$19,109	$19,899

Crude oil handling costs:			
Genesis affiliates	3,917	3,951	2,930
Shell affiliates	2,428	1,938	858
Total	$6,345	$5,889	$3,788
Other operating costs and expenses:			
Genesis affiliates	8,640	8,388	7,914
Total	$8,640	$8,388	$7,914

Other operating costs and expenses include amounts charged to us by Manta Ray for operator fees and space on their SS-332A platform.

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The following table summarizes our related party accounts receivable and accounts payable amounts at the dates indicated:

	At December 31,	
	2018	2017
Accounts receivable - related parties:		
Genesis affiliates	$—	$—
Shell affiliates	1,189	1,121
Total accounts receivable - related parties	$1,189	$1,121
Accounts payable - related parties:		
Genesis affiliates	2,392	2,175
Shell affiliates	272	209
Total accounts payable - related parties	$2,664	$2,384

Note 7. Significant Risks

Production and Credit Risk due to Customer Concentration
Offshore pipeline systems such as ours are directly impacted by exploration and production activities in the Gulf of Mexico for crude oil. Crude oil reserves are depleting assets. Our crude oil pipeline system must access additional reserves to offset either (i) the natural decline in production from existing connected wells or (ii) the loss of production to a competing takeaway pipeline. We actively seek to offset the loss of volumes due to depletion by adding connections to new customers and production fields.

In terms of percentage of total revenues, our largest customers for the year ended December 31, 2018 were Anadarko Petroleum Corporation 22.3%, Shell Oil Company 13.1%, and ExxonMobil Oil Corporation 12.5%. Our largest customers for the years ended December 31, 2017 and 2016, respectively, were Anadarko Petroleum Corporation 24.0% and 16.8%, Shell Oil Company 15.5% and 15.9%, and BHP Billiton Ltd. 10.6% and 9.7%. Shell Oil Company is a marketing agent for numerous producers who are dedicated to us. The loss of any of these customers or a significant reduction in the crude oil volumes they have dedicated to us for handling would have a material adverse effect on our financial position, results of operations and cash flows.