

Sanchez Midstream Partners LP
Form 10-Q
November 09, 2018
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2018

OR

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

For the transition period from _____ to _____ .

Commission File Number 001-33147

Sanchez Midstream Partners LP

(Exact name of registrant as specified in its charter)

Delaware	11-3742489
(State or Other Jurisdiction of	(I.R.S. Employer
Incorporation or Organization)	Identification No.)

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1000 Main Street, Suite 3000

Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 783-8000

(Registrant's Telephone Number, Including Area Code)

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

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

Large accelerated filer Accelerated filer Non accelerated filer Smaller reporting company Emerging growth company

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

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

Common units outstanding as of November 7, 2018: Approximately 16,188,926 units.

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Cautionary Note Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q (this “Form 10-Q”) contains “forward-looking statements” as defined by the United States Securities and Exchange Commission (the “SEC”) that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include discussions about our business strategy; our acquisition strategy; our financing strategy; our ability to make, maintain and grow distributions; our future operating results; the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements; the ability of our partners to perform under our joint ventures and partnerships; our future capital expenditures; and our plans, objectives, expectations, forecasts, outlook and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Part I, Item 2. and other items within this Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “negative of such terms or other comparable terminology.

The forward-looking statements contained in this Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by the management of our general partner. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate.

Important factors that could cause our actual results to differ materially from the expectations reflected in the forward looking statements include, among others:

- our ability to successfully execute our business, acquisition and financing strategies;
- our ability to make, maintain and grow distributions;
- the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements;
- the ability of our partners to perform under our joint ventures and partnerships;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- our ability to utilize the services, personnel and other assets of the sole member of our general partner, SP Holdings, LLC (“Manager”), pursuant to existing services agreements;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;
- the credit worthiness and performance of our counterparties, including financial institutions, operating partners and other parties;
- the timing and extent of changes in prices for, and demand for, natural gas, natural gas liquids (“NGLs”) and oil;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise;
- competition in the oil and natural gas industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the extent to which our assets operated by others are operated successfully and economically;
- our ability to compete with other companies in the oil and natural gas industry;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and

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regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;

- the use of competing energy sources and the development of alternative energy sources;
- unexpected results of litigation filed against us;
- disruptions due to extreme weather conditions, such as extreme rainfall, hurricanes or tornadoes;
- the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage; and
- the other factors described under “Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Part II, Item 1A. Risk Factors” and elsewhere in this Form 10-Q and in our other public filings with the SEC.

Management cautions all readers that the forward-looking statements contained in this Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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COMMONLY USED DEFINED TERMS

As used in this Form 10-Q, unless the context indicates or otherwise requires, the following terms have the following meanings:

- “Sanchez Midstream Partners,” “SNMP,” “the Partnership,” “we,” “us,” “our” or like terms refer collectively to Sanchez Midstream Partners LP, its consolidated subsidiaries and, where the context provides, the entity in which we have a 50% or more ownership interest.
- “Bbl” means a barrel of 42 U.S. gallons of oil.
- “Boe” means one barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.
- “Boe/d” means one Boe per day.
- “MBbl” means one thousand barrels of oil or other liquid hydrocarbons.
- “MBoe” means one thousand Boe.
- “Mcf” means one thousand cubic feet of natural gas.
- “MMBtu” means one million British thermal units.
- “MMcf/d” means one million cubic feet of natural gas per day.
- “NGLs” refers to the combination of ethane, propane, butane, natural gasolines and other components that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
- “our general partner” refers to Sanchez Midstream Partners GP LLC, our general partner.
- “Sanchez Energy” refers to Sanchez Energy Corporation (NYSE: SN) and its consolidated subsidiaries.
- “SOG” refers to Sanchez Oil & Gas Corporation, an entity that provides operational support to us.
- “SP Holdings” or “Manager” refers to SP Holdings, LLC, the sole member of our general partner.

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Operations

(In thousands, except unit data)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues				
Natural gas sales	\$ 166	\$ 787	\$ 865	\$ 5,818
Oil sales	2,848	3,061	7,894	22,520
Natural gas liquid sales	408	514	1,403	1,473
Gathering and transportation sales	1,582	14,234	4,931	39,621
Gathering and transportation lease revenues	13,148	—	38,634	—
Total revenues	18,152	18,596	53,727	69,432
Expenses				
Operating expenses				
Lease operating expenses	1,905	1,735	5,883	10,599
Transportation operating expenses	3,061	2,661	8,979	8,989
Cost of sales	—	—	—	77
Production taxes	292	340	901	1,166
General and administrative expenses	5,109	5,614	17,193	17,576
Unit-based compensation expense	155	631	2,940	1,951
Gain on sale of assets	(238)	(2,546)	(2,626)	(2,546)
Depreciation, depletion and amortization	6,507	6,899	19,680	28,017
Asset impairments	—	—	—	4,688
Accretion expense	123	149	372	647
Total operating expenses	16,914	15,483	53,322	71,164
Other (income) expense				
Interest expense, net	2,786	2,215	8,165	5,994
Earnings from equity investments	(2,313)	(2,873)	(9,696)	(4,397)
Other expense	352	—	1,876	—
Total other (income) expenses	825	(658)	345	1,597
Total expenses	17,739	14,825	53,667	72,761
Income (loss) before income taxes	413	3,771	60	(3,329)
Income tax expense	—	—	—	—
Net income (loss)	413	3,771	60	(3,329)
Less				
Preferred unit paid-in-kind distributions	—	—	(3,500)	(2,625)
Preferred unit distributions	(8,838)	(8,750)	(24,588)	(24,500)
Preferred unit amortization	(608)	(463)	(1,707)	(1,300)

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Net loss attributable to common unitholders	\$ (9,033)	\$ (5,442)	\$ (29,735)	\$ (31,754)
Net loss per unit				
Common units - Basic and Diluted	\$ (0.59)	\$ (0.38)	\$ (1.97)	\$ (2.29)
Weighted Average Units Outstanding				
Common units - Basic and Diluted	15,398,453	14,313,999	15,114,671	13,888,057

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

	September 30, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	\$ 2,311	\$ 321
Accounts receivable	65	495
Accounts receivable - related entities	6,682	13,099
Prepaid expenses	1,001	2,670
Fair value of commodity derivative instruments	13	942
Assets held for sale	914	—
Total current assets	10,986	17,527
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	112,516	170,750
Gathering and transportation assets	185,953	184,969
Less: accumulated depreciation, depletion, amortization and impairment	(97,472)	(142,574)
Oil and natural gas properties and equipment, net	200,997	213,145
Other assets		
Intangible assets, net	162,071	172,166
Fair value of commodity derivative instruments	85	1,318
Equity investments	117,677	123,715
Other non-current assets	452	552
Total assets	\$ 492,268	\$ 528,423
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	\$ 4,253	\$ 1,782
Accounts payable and accrued liabilities - related entities	5,570	10,353
Royalties payable	370	371
Fair value of commodity derivative instruments	2,710	756
Other liabilities	444	151
Total current liabilities	13,347	13,413
Other liabilities		
Asset retirement obligation	6,386	6,074
Long-term debt, net of debt issuance costs	182,300	187,808
Fair value of commodity derivative instruments	2,894	273
Other liabilities	7,834	6,251
Total other liabilities	199,414	200,406
Total liabilities	212,761	213,819
Commitments and contingencies (See Note 12)		
Mezzanine equity		
Class B preferred units, 31,310,896 and 31,000,887 units issued and outstanding as of September 30, 2018 and December 31, 2017, respectively	349,207	343,912

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Partners' deficit

Common units, 16,195,816 and 14,965,134 units issued and outstanding as of September 30, 2018 and December 31, 2017, respectively	(69,700)	(29,308)
Total partners' deficit	(69,700)	(29,308)
Total liabilities and partners' capital	\$ 492,268	\$ 528,423

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(unaudited)

	Nine Months Ended September 30,	
	2018	2017
Cash flows from operating activities:		
Net income (loss)	\$ 60	\$ (3,329)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	9,585	17,813
Amortization of debt issuance costs	498	391
Asset impairments	—	4,688
Accretion expense	372	647
Distributions from equity investments	18,572	5,329
Equity earnings in affiliate	(9,696)	(4,397)
Gain on sale of assets	(2,626)	(2,386)
Net (gains) losses on commodity derivative contracts	8,083	(7,584)
Net cash settlements received (paid) on commodity derivative contracts	(1,306)	5,093
Cash settlements on terminated commodity derivative contracts	—	3,602
Unit-based compensation	2,940	2,646
Loss on earnout derivative	1,876	—
Amortization of intangible assets	10,095	10,204
Costs for plug and abandon activities	—	(46)
Changes in Operating Assets and Liabilities:		
Accounts receivable	196	159
Accounts receivable - related entities	6,364	(1,042)
Prepaid expenses	1,669	(348)
Other assets	62	124
Accounts payable and accrued liabilities	10,307	6,416
Accounts payable and accrued liabilities- related entities	(4,932)	(1,033)
Royalties payable	(1)	(301)
Net cash provided by operating activities	52,118	36,646
Cash flows from investing activities:		
Final settlement of oil and natural gas properties acquisition	—	1,468
Development of oil and natural gas properties	(169)	(148)
Proceeds from sale of assets	6,209	5,510
Construction of gathering and transportation assets	(1,959)	(29,058)
Purchases of and contributions to equity affiliates	(2,838)	(10,380)
Net cash provided by (used in) investing activities	1,243	(32,608)
Cash flows from financing activities:		
Payments for offering costs	(50)	(611)
Proceeds from issuance of debt	2,000	45,500
Repayment of debt	(7,000)	(9,500)

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Issuance of common units	—	1,290
Distributions to common unitholders	(20,815)	(18,530)
Class B preferred unit cash distributions	(24,500)	(22,750)
Debt issuance costs	(1,006)	(27)
Net cash used in financing activities	(51,371)	(4,628)
Net increase (decrease) in cash and cash equivalents	1,990	(590)
Cash and cash equivalents, beginning of period	321	957
Cash and cash equivalents, end of period	\$ 2,311	\$ 367
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	\$ 450	\$ 2,414
Asset retirement obligation	\$ 288	\$ 198
Earnout derivative	\$ —	\$ 221
Cash paid during the period for interest	\$ 7,316	\$ 5,494

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Partners' Capital

(In thousands, except unit data)

(Unaudited)

	Common Units		Total
	Units	Amount	Capital
Partners' Deficit, December 31, 2017	14,965,134	\$ (29,308)	\$ (29,308)
Unit-based compensation programs	575,148	2,940	2,940
Issuance of common units, net of offering costs of \$0.1 million	655,534	7,218	7,218
Cash distributions to common unit holders	—	(20,815)	(20,815)
Distributions - Class B preferred units	—	(29,795)	(29,795)
Net income	—	60	60
Partners' Deficit, September 30, 2018	16,195,816	\$ (69,700)	\$ (69,700)

See accompanying notes to condensed consolidated financial statements.

	Common Units		Total
	Units	Amount	Capital
Partners' Capital, December 31, 2016	13,447,749	\$ 16,744	\$ 16,744
Unit-based compensation programs	212,481	2,648	2,648
Issuance of common units, net of offering costs of \$0.6 million	719,671	9,124	9,124
Cash distributions to common unit holders	—	(18,530)	(18,530)
Common units issued as Class B Preferred distributions	393,291	5,250	5,250
Distributions - Class B preferred units	—	(28,425)	(28,425)
Net loss	—	(3,329)	(3,329)
Partners' Deficit, September 30, 2017	14,773,192	\$ (16,518)	\$ (16,518)

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BUSINESS

Organization

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. The Partnership has ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, all located in the Western Eagle Ford in South Texas. We also own production assets in Texas and Louisiana. We have entered into a shared services agreement (the “Services Agreement”) with Manager, the sole member of our general partner, pursuant to which Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services. On June 2, 2017, we changed our name to Sanchez Midstream Partners LP. Manager owns the general partner of SNMP and all of SNMP’s incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol “SNMP.”

2. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Accounting policies used by us conform to accounting principles generally accepted in the United States of America (“U.S. GAAP”). These unaudited condensed consolidated financial statements include the accounts of us and our wholly owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation. Our business consists of two reportable segments: Production and Midstream. Midstream includes Western Catarina Midstream (defined in Note 10 “Intangible Assets”), the Carnero JV (defined in Note 11 “Investments”) and Seco Pipeline (defined in Note 13 “Related Party Transactions”). Our management evaluates performance based on these two segments.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the SEC. Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with U.S. GAAP, have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information presented not misleading. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary to fairly state the financial position, results of operations and cash flows with respect to the interim condensed consolidated financial statements have been included. The results of operations for the interim periods are not necessarily indicative of the results for the entire year.

These unaudited condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto of SNMP and its subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2017, which was filed with the SEC on March 12, 2018.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (“FASB”), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our condensed

consolidated financial statements upon adoption.

In August 2018, the FASB issued Accounting Standards Update (“ASU”) 2018-13 “Fair Value Measurement (ASC 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements,” which modifies the disclosure requirements on fair value measurements. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In June 2018, the FASB issued ASU 2018-07 “Compensation - Stock Compensation (Topic 718) - Improvements to Nonemployee Share-Based Payment Accounting,” which expands the scope of Topic 718, Compensation – Stock Compensation, to include share-based payment transactions for acquiring goods and services from nonemployees. This ASU is effective for public business entities for

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annual and interim periods in fiscal years beginning after December 15, 2018. We are currently in the process of evaluating the impact of adoption of this guidance on our condensed consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01 “Business Combinations (Topic 805) - Clarifying the Definition of a Business,” which provides a new framework for determining whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The Partnership adopted this ASU on January 1, 2018, using a prospective method.

In November 2016, the FASB issued ASU 2016-18 “Statement of Cash Flows (Topic 230): Restricted Cash,” which requires companies to include cash and cash equivalents that have restrictions on withdrawal or use in total cash and cash equivalents on the statement of cash flows. This ASU is now effective for public business entities beginning after December 15, 2017. The Partnership does not currently have restricted cash.

In October 2016, the FASB issued ASU 2016-16 “Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory,” which eliminates a current exception in U.S. GAAP to the recognition of the income tax effects of temporary differences that result from intra-entity transfers of non-inventory assets. The intra-entity exception is being eliminated under the ASU. The standard is required to be applied on a modified retrospective basis and is now effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The adoption of ASU 2016-16 did not have an impact on the Partnership’s unaudited condensed consolidated financial statements and related disclosures.

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019, and earlier adoption is permitted. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02 “Leases (Topic 842),” effective for annual and interim periods for public companies beginning after December 15, 2018. Additionally, in July 2018, the FASB issued ASU 2018-10, “Codification Improvements to Topic 842 (Leases),” which provides narrow amendments to clarify how to apply certain aspects of ASU 2016-02. The Partnership plans on electing the practical expedients disclosed in ASU 2018-10. The effective date in ASU 2018-10 is the same as that of ASU 2016-02. The standards update the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee’s classification of a finance lease. The Partnership will not early adopt this standard and will apply the revised lease rules for our interim and annual reporting periods starting January 1, 2019. The Partnership is currently evaluating the impact of these rules on its consolidated financial statements and has identified the population of leases under the revised definition. The Partnership is also in the process of implementing a lease accounting software to properly account for lease data upon adoption. Concurrent with the software implementation, the Partnership is implementing necessary updates to its business processes and controls. The adoption of this standard will result in an increase in the assets and liabilities on the Partnership’s consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” In March, April, May and December of 2016, the FASB issued rules clarifying several aspects of the new revenue recognition standard. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. This

guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new standard also requires more detailed disclosures related to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The Partnership adopted the standard effective January 1, 2018. For more information, see Note 3 “Revenue Recognition.”

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership’s financial position, results of operations and cash flows.

Estimates

The condensed consolidated financial statements are prepared in conformity with U.S. GAAP, which requires management to

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make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and accompanying footnotes. These estimates and the underlying assumptions affect the amounts of assets and liabilities reported, disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include estimates of our reserves of natural gas, NGLs and oil; future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of derivatives; and fair values of assets and liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best judgment using the data available. Management evaluates its estimates and assumptions on an on-going basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from the estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

3. REVENUE RECOGNITION

Adoption of Topic 606

Effective January 1, 2018, the Partnership adopted the new Accounting Standards Codification ("ASC") 606, Revenue from Contracts with Customers, and all the related amendments (collectively referred to as "Topic 606") to all open contracts using the modified retrospective approach. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

For contracts that have a contract term of one year or less, we elected to utilize the practical expedient permitted under the rules of adoption whereby a Company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Adoption of this guidance resulted in financial statement presentation changes whereby revenue from the Gathering Agreement and revenue from the Seco Pipeline Transportation Agreement (as each term is defined in Note 13 "Related Party Transactions") are shown as separate line items within our condensed consolidated statements of operations. There was no cumulative adjustment to retained earnings or any other changes to our January 1, 2018 condensed consolidated balance sheet.

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Topic 606. The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

Disaggregation of Revenue

We disaggregate revenue based on type of revenue and product type. In selecting the disaggregation categories, we considered a number of factors, including disclosures presented outside the financial statements, such as in our

earnings release and investor presentations, information reviewed internally for evaluating performance, and other factors used by the Partnership or the users of its financial statements to evaluate performance or allocate resources. We have concluded that disaggregating revenue by type of revenue and product type appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

Midstream Segment

The Seco Pipeline Transportation Agreement is our only contract that we account for under Topic 606. The Catarina Midstream Gathering Agreement was classified as an operating lease at inception and is accounted for under ASC 840, Leases, and is reported as gathering and transportation lease revenue in our condensed consolidated statements of operations. Both of these contracts are further discussed in Note 13 “Related Party Transactions.”

We account for income from our unconsolidated equity method investments as earnings from equity investments in our condensed consolidated statements of operations. Earnings from these equity method investments are further discussed in Note 11 “Investments.”

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Production Segment

Our oil, natural gas, and NGL revenue is marketed and sold on our behalf by the respective asset operators. We are not party to the contracts with the third-party customers. However, we are party to joint operating agreements, which we account for under ASC 808, and revenue for these arrangements is recognized based on the information provided to us by the operators.

We additionally recognize and present changes in the fair value of our commodity derivative instruments within natural gas sales and oil sales in the condensed consolidated statements of operations. As this income is accounted for under ASC 815, Derivatives and Hedging, it is not subject to Topic 606.

We recognized revenue of \$18.2 million for three months ended September 30, 2018. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Three Months Ended		
	September 30, 2018		
	Production	Midstream	Total
Revenues:			
Natural gas sales	\$ 166	\$ —	\$ 166
Oil sales	2,848	—	2,848
Natural gas liquid sales	408	—	408
Gathering and transportation sales	—	1,582	1,582
Gathering and transportation lease revenues	—	13,148	13,148
Total revenues	\$ 3,422	\$ 14,730	\$ 18,152

We recognized revenue of \$53.7 million for nine months ended September 30, 2018. The following table displays revenue disaggregated by type of revenue and product type (in thousands):

	Nine Months Ended September 30, 2018		
	Production	Midstream	Total
Revenues:			
Natural gas sales	\$ 865	\$ —	\$ 865
Oil sales	7,894	—	7,894
Natural gas liquid sales	1,403	—	1,403
Gathering and transportation sales	—	4,931	4,931
Gathering and transportation lease revenues	—	38,634	38,634
Total revenues	\$ 10,162	\$ 43,565	\$ 53,727

Performance Obligations

Under the Seco Pipeline Transportation Agreement, we agreed to provide transportation services of certain quantities of natural gas from the receipt point to the delivery point. Each MMBtu of natural gas transported is distinct and the transportation services performed on each distinct molecule of product is substantially the same in nature. As such, we applied the series guidance and treat these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. The Seco Pipeline Transportation Agreement requires payment within 30 days following the calendar month of delivery.

The Seco Pipeline Transportation Agreement contains variable consideration in the form of volume variability. As the distinct goods or services (rather than the series) are considered for the purpose of allocating variable consideration,

we have taken the optional exception under ASC 606-10-50-14A(b) which is available only for wholly unsatisfied performance obligations for which the criteria in ASC 606-10-32-40 have been met. Under this exception, neither estimation of variable consideration nor disclosure of the transaction price allocated to the remaining performance obligations is required. Revenue is alternatively recognized in the period that control is transferred to the customer and the respective variable component of the total transaction price is resolved.

For forms of variable consideration that are not associated with a specific volume (such as late payment fees) and thus do not meet allocation exception, estimation is required. These fees, however, are immaterial to our condensed consolidated financial statements and have a low probability of occurrence. As significant reversals of revenue due to this variability are not probable, no estimation is required.

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Contract Balances

Under our sales contracts, we invoice customers after our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under Topic 606. At January 1, 2018 and September 30, 2018, our receivables from contracts with customers were \$1.1 million and \$0.7 million, respectively, and are presented within accounts receivable – related entities on the condensed consolidated balance sheets.

Reconciliation of Statements of Operations

The impact of adopting Topic 606 on our condensed consolidated statements of operations is as follows (in thousands):

	Three Months Ended September 30, 2018		
	As reported	Balances without Adoption Topic 606	Effect of change Higher/(Lower)
Statement of Operations			
Gathering and transportation sales	\$ 1,582	\$ 14,730	\$ (13,148)
Gathering and transportation lease revenues	13,148	—	13,148
Net earnings	\$ 14,730	\$ 14,730	\$ —

	Nine Months Ended September 30, 2018		
	As reported	Balances without Adoption Topic 606	Effect of change Higher/(Lower)
Statement of Operations			
Gathering and transportation sales	\$ 4,931	\$ 43,565	\$ (38,634)
Gathering and transportation lease revenues	38,634	—	38,634
Net earnings	\$ 43,565	\$ 43,565	\$ —

We expect the impact of the adoption of Topic 606 to be immaterial to our net income (loss) on an ongoing basis.

4. ACQUISITIONS AND DIVESTITURES

Louisiana Divestiture

In September 2018, we entered into a purchase and sale agreement to sell certain non-operated production assets located in Louisiana for cash consideration of approximately \$1.3 million. The divestiture closed on October 22, 2018, and we anticipate recording a gain on the sale. As of September 30, 2018, we reclassified \$0.9 million of oil and natural gas properties to assets held for sale on the condensed consolidated balance sheet related to the carrying amount of these assets.

Briggs Divestiture

In April 2018, we entered into a purchase and sale agreement to sell specified wellbores and other associated assets and interests in La Salle County Texas (the “Briggs Assets”) for a base purchase price of approximately \$4.5 million which, after giving effect to purchase price adjustments, was reduced to approximately \$4.2 million (the “Briggs Divestiture”). In addition, other than a limited amount of retained obligations, the buyer agreed to assume all obligations relating to the Briggs Assets, including all plugging and abandonment costs, that may arise on or after March 1, 2018. The Briggs Divestiture closed April 30, 2018, and we recorded a gain of approximately \$1.8 million on the sale.

Cola Divestiture

In April 2018, we entered into a purchase and sale agreement to sell certain non-operated production assets located in Oklahoma for cash consideration of approximately \$1.0 million. The divestiture closed on April 30, 2018, and we recorded a gain of approximately \$1.1 million on the sale.

Texas Production Divestiture

In October 2017, we entered into a purchase and sale agreement to sell specified oil and gas wells, leases and other associated assets and interests located in Texas (the “Texas Production Assets”) for cash consideration of approximately \$6.3 million (the “Texas

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Production Divestiture”). In addition, the buyer agreed to assume all obligations relating to the Texas Production Assets, including all plugging and abandonment costs, that may arise on or after October 1, 2017. The Texas Production Divestiture closed on November 13, 2017, and we recorded a gain of approximately \$1.4 million on the sale.

Oklahoma Non-Operated Production Divestiture

In July 2017, we entered into an agreement to assign our interest in certain non-operated production assets located in Oklahoma, as well as our equity interests in the entities that owned such assets, in exchange for agreeing upon the apportionment of certain shared litigation costs. The assignment became effective as of July 14, 2017.

Oklahoma Production Divestiture

In May 2017, we entered into a purchase and sale agreement to sell all of the Partnership’s equity interests in the entities that owned our remaining operated Oklahoma production assets for cash consideration of \$5.5 million, and assumption by the buyer of all obligations relating to such assets arising after the closing date and all plugging and abandonment costs relating to the assets arising prior to the closing date (the “Oklahoma Production Divestiture”). The Oklahoma Production Divestiture closed on July 17, 2017, and we recorded a gain of \$2.4 million on the sale.

5. FAIR VALUE MEASUREMENTS

Measurements of fair value of derivative instruments are classified according to the fair value hierarchy, which prioritizes the inputs to the valuation techniques used to measure fair value. Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the term of the instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2018 (in thousands):

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Fair Value Measurements at September 30, 2018

	Active Market for Identical Instruments (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative liability	\$ —	\$ (5,506)	\$ —	\$ (5,506)
Midstream derivative instrument				
Earnout derivative liability	—	—	(8,278)	(8,278)
Total	\$ —	\$ (5,506)	\$ (8,278)	\$ (13,784)

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The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2017 (in thousands):

	Fair Value Measurements at December 31, 2017			Fair Value
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	
Commodity derivative instrument				
Derivative assets	\$ —	\$ 1,231	\$ —	\$ 1,231
Midstream derivative instrument				
Earnout derivative liability	—	—	(6,402)	(6,402)
Total	\$ —	\$ 1,231	\$ (6,402)	\$ (5,171)

As of September 30, 2018 and December 31, 2017, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of Topic 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. We periodically review oil and natural gas properties for impairment when facts and circumstances indicate that their carrying values may not be recoverable.

A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 9 "Asset Retirement Obligation."

We had no non-recurring fair value measurements of our assets as of September 30, 2018. However, the following table summarizes the non-recurring fair value measurements of our assets as of December 31, 2017 (in thousands):

	Fair Value Measurements at December 31, 2017		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment(a)	\$ —	\$ —	\$ 7,277
Total net assets	\$ —	\$ —	\$ 7,277

(a) During the year ended December 31, 2017, we recorded a non-cash impairment charge of \$4.7 million to impair our producing oil and natural gas properties. The carrying values of the impaired properties were reduced to a fair value of \$7.3 million, estimated using inputs characteristic of a Level 3 fair value measurement.

The fair values of oil and natural gas properties and related equipment were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties and related equipment include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; (v) estimated throughput; and (vi) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

Fair Value of Financial Instruments

The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Credit Agreement – We believe that the carrying value of long-term debt for our Credit Agreement (defined in Note 7 “Long-Term Debt”) approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our Credit Agreement is discussed further in Note 7 “Long-Term Debt.”

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate

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derivatives as of September 30, 2018. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

Earnout Derivative – As part of the Carnero Gathering Transaction (defined in Note 11 “Investments”), we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. The earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. We have therefore classified the fair value measurements of our earnout derivative as Level 3 and currently present it within the other liabilities lines on the condensed consolidated balance sheets.

The following table sets forth a reconciliation of changes in the fair value of the Partnership's earnout derivative classified as Level 3 in the fair value hierarchy (in thousands):

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Beginning balance	\$ (6,402)	\$ (4,270)
Initial fair value of earnout derivative	—	221
Loss on earnout derivative	(1,876)	(2,353)
Ending balance	\$ (8,278)	\$ (6,402)
Loss included in earnings related to derivatives still held as of September 30, 2018 and December 31, 2017, respectively	\$ (1,876)	\$ (2,353)

6. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under Topic 815, “Derivatives and Hedging,” all derivative instruments are recorded on the condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives’ fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have not elected to designate any of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included in natural gas sales and oil sales in the condensed consolidated statements of operations.

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As of September 30, 2018, we had the following derivative contracts in place for the periods indicated, all of which are accounted for as mark-to-market activities:

Fixed Price Basis Swaps – West Texas Intermediate (WTI)

	Three Months Ended (volume in Bbls)		June 30,		September 30,		December 31,		Total	Average
	March 31,	Average	Volume	Average	Volume	Average	Volume	Average		
	Volume	Price	Volume	Price	Volume	Price	Volume	Price	Volume	Price
2018	—	\$ —	—	\$ —	—	\$ —	59,704	\$ 59.84	59,704	\$ 59.84
2019	62,528	\$ 60.41	59,552	\$ 60.44	57,024	\$ 60.48	54,824	\$ 60.52	233,928	\$ 60.46
2020	52,776	\$ 53.50	50,960	\$ 53.50	49,224	\$ 53.50	47,624	\$ 53.50	200,584	\$ 53.50
									494,216	

Fixed Price Swaps – NYMEX (Henry Hub)

	Three Months Ended (volume in MMBtu)		June 30,		September 30,		December 31,		Total	Average
	March 31,	Average	Volume	Average	Volume	Average	Volume	Average		
	Volume	Price	Volume	Price	Volume	Price	Volume	Price	Volume	Price
2018	—	\$ —	—	\$ —	—	\$ —	117,040	\$ 3.00	117,040	\$ 3.00
2019	119,832	\$ 2.85	115,784	\$ 2.85	112,032	\$ 2.85	108,552	\$ 2.85	456,200	\$ 2.85
2020	105,104	\$ 2.85	102,008	\$ 2.85	99,136	\$ 2.85	96,200	\$ 2.85	402,448	\$ 2.85
									975,688	

The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the nine months ended September 30, 2018 and the year ended December 31, 2017 (in thousands):

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Beginning fair value of commodity derivatives	\$ 1,231	\$ 6,436
Net gains (losses) on crude oil derivatives	(8,110)	3,284
Net gains on natural gas derivatives	27	663
Net settlements paid (received) on derivative contracts:		
Oil	1,383	(6,422)
Natural gas	(37)	(2,730)
Ending fair value of commodity derivatives	\$ (5,506)	\$ 1,231

The effect of derivative instruments on our condensed consolidated statements of operations was as follows (in thousands):

Location of Gain(Loss)	Amount of Gain (Loss) in Income	
	Three Months Ended September 30,	Nine Months Ended September 30,

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Derivative Type	in Income	2018	2017	2018	2017
Commodity – Mark-to-Market	Oil sales	\$ (2,454)	\$ (1,456)	\$ (8,110)	\$ 7,087
Commodity – Mark-to-Market	Natural gas sales	23	(228)	27	497
		\$ (2,431)	\$ (1,684)	\$ (8,083)	\$ 7,584

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with four counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments. In August 2017, we repositioned certain of our crude oil and natural gas hedges in anticipation of the sale of the Texas Production Assets and, in the process, received \$3.6 million in net cash from the counterparties on those hedges. As of September 30, 2018 and December 31, 2017, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Earnout Derivative

Refer to Note 5 “Fair Value Measurements”.

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7. LONG-TERM DEBT

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (the “Credit Agreement”). The Credit Agreement provides a maximum commitment of \$500.0 million and has a maturity date of March 31, 2020. Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that we own, as well as various security and pledge agreements among the Partnership, certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of \$15.0 million which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was \$200.0 million. The borrowing base for the credit available for the upstream oil and gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is generally equal to the rolling four quarter Adjusted EBITDA of our midstream operations, together with the amount of distributions received from Carnero JV (defined in Note 11 “Investments”) multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders. As of September 30, 2018, the borrowing base under the Credit Agreement was \$310.0 million, with an elected commitment amount of \$210.0 million, and we had \$184.0 million of debt outstanding under the facility, leaving us with \$26.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of September 30, 2018. Our Credit Agreement matures on March 31, 2020.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank rate (“LIBOR”) plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) a domestic bank rate (“ABR”) plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus (iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

- current assets to current liabilities of at least 1.0 to 1.0 at all times;
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the adjusted EBITDA of our midstream operations equals or exceeds one-third of total Adjusted EBITDA or 4.0 to 1.0 if the adjusted EBITDA of our midstream operations is less than one-third of total adjusted EBITDA; and
- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed to be made,

violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

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At September 30, 2018, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt under the Credit Agreement could become then due and payable. We may request waivers of compliance for any violation of a financial covenant from the lenders, but there is no assurance that such waivers would be granted.

Debt Issuance Costs

As of September 30, 2018 and December 31, 2017, our unamortized debt issuance costs were \$1.7 million and \$1.2 million, respectively. These costs are amortized to interest expense in our condensed consolidated statements of operations over the life of our Credit Agreement. Amortization of debt issuance costs recorded during the three months ended September 30, 2018 was \$0.2 million and \$0.1 million for the three months ended September 30, 2017. Amortization of debt issuance costs recorded during the nine months ended September 30, 2018 was \$0.5 million and \$0.4 million for the nine months ended September 30, 2017.

8. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

Gathering and transportation assets consisted of the following (in thousands):

	September 30, 2018	December 31, 2017
Gathering and transportation assets		
Midstream assets	\$ 185,953	\$ 184,969
Less: Accumulated depreciation and amortization	(32,639)	(26,870)
Total gathering and transportation assets	\$ 153,314	\$ 158,099

Oil and natural gas properties consisted of the following (in thousands):

	September 30, 2018	December 31, 2017
Oil and natural gas properties and related equipment		
Proved property	\$ 112,516	\$ 170,750
Less: Accumulated depreciation, depletion, amortization and impairments	(64,833)	(115,704)
Oil and natural gas properties and equipment, net	\$ 47,683	\$ 55,046

Oil and Natural Gas Properties. We follow the successful efforts method of accounting for our oil and natural gas production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties.

Depreciation, Depletion and Amortization. Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves.

All other properties, including the gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range

from 3 to 15 years for furniture and equipment, and up to 36 years for gathering facilities.

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Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Depreciation, depletion and amortization of oil and natural gas-related assets	\$ 1,202	\$ 1,739	\$ 3,816	\$ 7,850
Depreciation and amortization of gathering and transportation related assets	1,940	1,780	5,769	9,963
Amortization of intangible assets	3,365	3,380	10,095	10,204
Total Depreciation, depletion and amortization	6,507	6,899	19,680	28,017
Asset impairments	—	—	—	4,688
Total	\$ 6,507	\$ 6,899	\$ 19,680	\$ 32,705

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets. Oil and natural gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates are based upon reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Other significant inputs, besides reserves, used to determine the fair values of proved properties include estimates of: (i) future operating and development costs; (ii) future commodity prices; and (iii) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Cash flow estimates for impairment testing exclude derivative instruments.

The recoverability of gathering and transportation assets is evaluated when facts or circumstances indicate that their carrying value may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows, we recognize an impairment equal to the excess of net book value over fair value. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our gathering and transportation assets and the recognition of additional impairments. Upon disposition or retirement of gathering and transportation assets, any gain or loss is recorded to operations.

For the three months and nine months ended September 30, 2018, we recorded no impairment charges. For the three months ended September 30, 2017, we recorded no impairment charges. For the nine months ended September 30, 2017 we recorded non-cash charges of \$4.7 million to impair certain of our producing oil and natural gas properties in Texas.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost ("ARC") is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities or gathering and transportation assets. Subsequently, the ARC is depreciated using

the units-of-production method for production assets and the straight-line method for midstream assets. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas properties, equipment and facilities or gathering and transportation assets.

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The following table is a reconciliation of changes in ARO (in thousands):

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Asset retirement obligation, beginning balance	\$ 6,074	\$ 13,579
Liabilities added from escalating working interests	288	198
Sales	(348)	(8,416)
Settlements	—	(60)
Accretion expense	372	773
Asset retirement obligation, ending balance	\$ 6,386	\$ 6,074

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. During the nine months ended September 30, 2018 and the year ended December 31, 2017, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs. During the nine months ended September 30, 2018, obligations were sold as part of the Briggs Divestiture and during the year ended December 31, 2017, obligations were sold as part of the Oklahoma Production Divestiture and the Texas Production Divestiture.

10. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes \$162.1 million related to the Gathering Agreement (defined in Note 13 “Related Party Transactions”) with Sanchez Energy that was entered into as part of the acquisition of the Western Catarina gathering system (“Western Catarina Midstream”). Pursuant to the 15-year agreement, Sanchez Energy tenders all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina area of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15-year life of the agreement.

Amortization expense for the nine months ended September 30, 2018 and 2017 was \$10.1 million and \$10.2 million, respectively. These costs are amortized to depreciation, depletion, and amortization expense in our condensed consolidated statements of operations. The following table is a reconciliation of changes in intangible assets (in thousands):

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Beginning balance	\$ 172,166	\$ 185,766
Disposals	—	(32)
Amortization	(10,095)	(13,568)
Ending balance	\$ 162,071	\$ 172,166

11. INVESTMENTS

In July 2016, we completed a transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Gathering, LLC (“Carnero Gathering”), a joint venture that was 50% owned and operated by Targa Resources Corp. (NYSE: TRGP) (“Targa”), for an initial payment of approximately \$37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately \$7.4 million as of the acquisition date (the “Carnero Gathering Transaction”). The fair value of the intangible asset for the contractual customer relationship related to Carnero Gathering was valued at approximately \$13.0 million. This amount is being amortized over a contract term of 15 years and decreases the earnings from equity investments line within the condensed consolidated statements of operations. As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. See Note 5 “Fair Value Measurements” for further discussion of the earnout derivative.

In November 2016, we completed a transaction pursuant to which we acquired from Sanchez Energy a 50% interest in Carnero Processing, LLC (“Carnero Processing”), a joint venture that was 50% owned and operated by Targa, for aggregate cash consideration of approximately \$55.5 million and the assumption of remaining capital contribution commitments to Carnero Processing, estimated at approximately \$24.5 million as of the date of acquisition (the “Carnero Processing Transaction”).

In May 2018, we executed a series of agreements with Targa pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering and Carnero Processing (the “Carnero JV Transaction”) to form an expanded 50 / 50 joint venture in South Texas, Carnero G&P, LLC (“Carnero JV”), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant (“Silver Oak II”), located in Bee County Texas, to Carnero JV, which expands the processing capacity of the joint

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venture from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the Carnero Gathering Line to Carnero JV resulting in the joint venture owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) the joint venture received a new dedication of over 315,000 Comanche acres in the Western Eagle Ford, operated by Sanchez Energy. As a result of the Carnero JV Transaction we now record our share of earnings and losses from Carnero JV using the Hypothetical Liquidation at Book Value (“HLBV”) method of accounting, beginning with the three months ended June 30, 2018. The HLBV is a balance-sheet approach that calculates the amount we would have received if Carnero JV were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our condensed consolidated statements of operations. In the event of liquidation of Carnero JV, available proceeds are first distributed to any priority return and unpaid capital associated with Silver Oak II, and then to members in accordance with their capital accounts.

As of September 30, 2018, the Partnership had paid approximately \$123.8 million for its investment in Carnero JV related to the initial payments and contributed capital. The Partnership has accounted for this investment using the equity method. Targa is the operator of the joint venture and has significant influence with respect to the normal day-to-day construction and operating decisions. We have included the investment balance in the equity investments caption on our condensed consolidated balance sheets. For the three months ended September 30, 2018, the Partnership recorded earnings of approximately \$2.6 million in equity investments from Carnero JV, which was offset by approximately \$0.3 million related to the amortization of the contractual customer intangible asset. For the nine months ended September 30, 2018, the Partnership recorded earnings of approximately \$10.6 million in equity investments from Carnero JV, which was offset by approximately \$0.9 million related to the amortization of the contractual customer intangible asset. We have included these equity method earnings in the earnings from equity investments line within the condensed consolidated statements of operations. Cash distributions of approximately \$18.6 million were received during the nine months ended September 30, 2018.

Summarized financial information of unconsolidated entities is as follows (in thousands):

	Nine Months Ended September 30,	
	2018	2017
Sales	\$ 257,470	\$ 57,406
Total expenses	234,341	46,734
Net income	\$ 23,129	\$ 10,672

	September 30, 2018	December 31, 2017
Current assets	\$ 38,501	\$ 38,344
Noncurrent assets	292,253	193,748
Current liabilities	26,387	24,710

12. COMMITMENTS AND CONTINGENCIES

As part of the Carnero Gathering Transaction, we are required to pay Sanchez Energy an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Sanchez Energy and other producers. This earnout has an approximate value of \$8.3 million and was recorded on the balance sheet as other liabilities as of September 30, 2018. For the three and nine months ended September 30, 2018 and 2017, natural gas received did not exceed the threshold.

13. RELATED PARTY TRANSACTIONS

See our Annual Report on Form 10-K for a more complete description of our Sanchez-Related Agreements and Sanchez-Related Transactions that were entered into prior to 2018. The following are updates to such disclosure:

In conjunction with the acquisition of Western Catarina Midstream, we entered into a 15-year gas gathering agreement with Sanchez Energy pursuant to which Sanchez Energy agreed to tender all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres in the Western Catarina area of the Eagle Ford Shale in South Texas for processing and transportation through Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the "Gathering Agreement"). On June 30, 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by a subsidiary of Sanchez Energy based on water that is delivered through the gathering system through March 31, 2018. Subsequent to the conclusion of the incremental infrastructure fee amendment, the parties have agreed to continue the incremental infrastructure fee on a month-to-month basis.

In May 2018, we executed the Carnero JV Transaction with Targa. In connection with the Carnero JV Transaction, effective April 1, 2018, a subsidiary of Sanchez Energy and Carnero JV entered into a Firm Gas Gathering, Processing and Purchase Agreement (the

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“Carnero Gas Gathering Agreement”) and other related documentation providing for certain gas gathering, treating and processing services in exchange for an approximately 315,000 gross acreage dedication from the subsidiary of Sanchez Energy and its working interest partners. Additionally, effective April 1, 2018, and in connection with the Carnero JV Transaction, another subsidiary of Sanchez Energy and an affiliate of Targa also amended their Firm Gas Gathering Agreement (the “Amended Gathering Agreement”) and Firm Gas Processing Agreement (the “Amended Processing Agreement”) which were subsequently assigned by the Targa counterparty to Carnero JV.

As of September 30, 2018 and December 31, 2017, the Partnership had a net receivable from related parties of approximately \$6.7 million, and \$13.1 million, respectively, which are included in accounts receivable – related entities on the condensed consolidated balance sheets. As of September 30, 2018 and December 31, 2017, the Partnership also had a net payable to related parties of approximately \$5.6 million, and \$10.4 million, respectively, which are included in accounts payable – related entities on the condensed consolidated balance sheets. The net receivable/payable as of September 30, 2018 and December 31, 2017 consist primarily of revenues receivable from oil and natural gas production and transportation, offset by costs associated with that production and transportation and obligations for general and administrative costs.

14. UNIT-BASED COMPENSATION

The Sanchez Midstream Partners LP Long-Term Incentive Plan (the “LTIP”) allows for grants of restricted common units. Restricted common unit activity under the LTIP during the period is presented in the following table:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2017	283,138	\$ 14.64
Granted	622,534	11.94
Vested	(236,495)	13.62
Returned/Cancelled	(47,386)	12.50
Outstanding at September 30, 2018	621,791	\$ 12.49

In April 2018, the Partnership issued 63,630 restricted common units pursuant to the LTIP to certain directors of the Partnership’s general partner that vested immediately on the date of grant. In April 2018, the Partnership issued 244,813 and 314,091 restricted common units pursuant to the LTIP to executives that vest on the first anniversary of the date of grant and to non-executive employees that vest over three years from the date of grant, respectively.

In March 2017, the Partnership issued 171,231 restricted common units pursuant to the LTIP to executives of the Partnership’s general partner that vested on the first anniversary of the date of grant in March 2018. The unit-based compensation expense for the award was based on the fair value on the day before the date of grant.

As of September 30, 2018, 1,215,697 common units remained available for future issuance to participants under the LTIP.

15. DISTRIBUTIONS TO UNITHOLDERS

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The table below reflects the payment of cash distributions on common units related to the nine months ended September 30, 2018 and the year ended December 31, 2017.

Three months ended	Distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2017	\$ 0.4375	May 10, 2017	May 22, 2017	May 31, 2017
June 30, 2017	\$ 0.4441	August 9, 2017	August 22, 2017	August 31, 2017
September 30, 2017	\$ 0.4508	November 7, 2017	November 20, 2017	November 30, 2017
December 31, 2017	\$ 0.4508	February 8, 2018	February 20, 2018	February 28, 2018
March 31, 2018	\$ 0.4508	May 8, 2018	May 22, 2018	May 31, 2018
June 30, 2018	\$ 0.4508	August 8, 2018	August 21, 2018	August 31, 2018
September 30, 2018	\$ 0.15	November 9, 2018	November 20, 2018	November 30, 2018

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The table below reflects the payment of distributions on Class B Preferred Units (defined below) related to the nine months ended September 30, 2018, and the year ended December 31, 2017.

	Cash distribution per unit	Date of declaration	Date of record	Date of distribution
Three months ended March 31, 2017 (a)	\$ 0.2258	May 10, 2017	May 22, 2017	May 31, 2017
June 30, 2017	\$ 0.28225	August 9, 2017	August 22, 2017	August 31, 2017
September 30, 2017	\$ 0.28225	November 7, 2017	November 20, 2017	November 30, 2017
December 31, 2017	\$ 0.28225	February 8, 2018	February 20, 2018	February 28, 2018
March 31, 2018	\$ 0.28225	May 8, 2018	May 22, 2018	May 31, 2018
June 30, 2018 (b)	\$ 0.2258	August 8, 2018	August 21, 2018	August 31, 2018
September 30, 2018	\$ 0.28225	November 9, 2018	November 20, 2018	November 30, 2018

(a) The Partnership elected to pay the first quarter 2017 distribution on the Class B Preferred Units in part cash and, with consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B Preferred Units). Accordingly, the Partnership declared a cash distribution of \$0.2258 per Class B preferred unit and an aggregate distribution of 184,697 common units, each payable on May 31, 2017 to holders of record on May 22, 2017.

(b) The Partnership elected to pay the second quarter 2018 distribution on the Class B Preferred Units in part cash and part in Class B Preferred Units. Accordingly, the Partnership declared a cash distribution of \$0.2258 per Class B Preferred Unit and an aggregate distribution of 310,009 Class B Preferred Units, each payable on August 31, 2018 to holders of record on August 21, 2018.

16. PARTNERS' CAPITAL

Outstanding Units

As of September 30, 2018, we had 31,310,896 Class B Preferred Units outstanding, and 16,195,816 common units outstanding, which included 621,791 unvested restricted common units issued under the LTIP.

Common Unit Issuances

The following table shows the common units issued by the Partnership in 2017 and 2018 to SP Holdings in connection with providing services under the Services Agreement:

	Common units	Date of issuance
Three months ended September 30, 2016	170,750	March 6, 2017
December 31, 2016	154,737	March 6, 2017
March 31, 2017	139,110	June 30, 2017
June 30, 2017	170,497	August 31, 2017
September 30, 2017	186,942	November 30, 2017
December 31, 2017	210,978	March 15, 2018
March 31, 2018	220,214	May 31, 2018

June 30, 2018 224,342 September 10, 2018

The Partnership elected to pay the first quarter 2017 distribution on the Class B Preferred Units in part cash and, with the consent of Stonepeak Catarina Holdings LLC (“Stonepeak”), the holder of our Class B Preferred Units, in part common units (in lieu of additional Class B Preferred Units). Accordingly, the Partnership issued 184,697 common units on May 22, 2017, to Stonepeak.

In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately \$1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015 as updated by that certain prospectus supplement filed with the SEC on April 6, 2017 (the “Shelf Registration Statement”). The Shelf Registration Statement allows the Partnership to sell up to \$50.0 million of common units by any method deemed an “at the market offering” (as such term is defined in Rule 415 of the Securities Act of 1933, as amended). Proceeds from such sales are expected to be used to fund general limited partnership purposes, including possible acquisitions. Proceeds from the 2017 at-the-market equity issuance were used for general limited partnership purposes.

Class B Preferred Unit Offering

On October 14, 2015, pursuant to that certain Class B Preferred Unit Purchase Agreement dated September 25, 2015 between the Partnership and Stonepeak, the Partnership sold and Stonepeak purchased 19,444,445 of the Partnership’s newly created Class B Preferred Units (the “Class B Preferred Units”) in a privately negotiated transaction for an aggregate cash purchase price of \$18.00 per Class B Preferred Unit, which resulted in gross proceeds to the Partnership of approximately \$350.0 million. The Partnership used the

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net proceeds to pay a portion of the consideration for the acquisition of Western Catarina Midstream, along with the payment to Stonepeak of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

Under the terms of our partnership agreement, holders of the Class B Preferred Units receive a quarterly distribution, at the election of the board of directors of our general partner, of 10.0% per annum if paid in full in cash or 12.0% per annum if paid in part cash (8.0% per annum) and in part Class B Preferred PIK Units (4.0% per annum), as defined in the Second Amended and Restated Agreement of Limited Partnership of the Partnership (the “Amended Partnership Agreement”). Distributions are to be paid on or about the last day of each of February, May, August and November after the end of each quarter.

In accordance with the partnership agreement, on December 6, 2016 we issued an additional 9,851,996 Class B Preferred Units to Stonepeak. On January 25, 2017, the Partnership and Stonepeak entered into a Settlement Agreement and Mutual Release (the “Settlement Agreement”) to settle a dispute arising from the calculation of an adjustment to the number of Class B Preferred Units pursuant to Section 5.10(g) of the Amended Partnership Agreement. Pursuant to the Settlement Agreement, and in accordance with Section 5.4 of the Amended Partnership Agreement, the Partnership issued 1,704,446 Class B Preferred Units to Stonepeak in a privately negotiated transaction as partial consideration for the Settlement Agreement, with the “Class B Preferred Unit Price” being established at \$11.29 per Class B Preferred Unit. Pursuant to the terms of the Amended Partnership Agreement, the Class B Preferred Units are convertible at any time, at the option of Stonepeak, into common units of the Partnership, subject to the requirement to convert a minimum of \$17.5 million of Class B Preferred Units. The issuance of the Class B Preferred Units pursuant to the Settlement Agreement was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

The Partnership elected to pay the second quarter 2018 distribution on the Class B Preferred Units in part cash and part Class B Preferred PIK Units in accordance with the partnership agreement. Accordingly, the Partnership issued 310,009 Class B Preferred Units on August 31, 2018, to Stonepeak.

The Class B Preferred Units are accounted for as mezzanine equity on the condensed consolidated balance sheets. The following table sets forth a reconciliation of the changes in mezzanine equity (in thousands):

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Mezzanine equity, beginning balance	\$ 343,912	\$ 342,991
Amortization of discount	1,707	1,796
Distributions	28,088	35,875
Distributions paid	(24,500)	(36,750)
Mezzanine equity, ending balance	\$ 349,207	\$ 343,912

Earnings per Unit

Net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income (loss) based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. The two-class method dictates that net income (loss) for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income (loss) be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income (loss) as if all of the net income for the period had been distributed in accordance with the partnership agreement. Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of

determining net income (loss) per unit. Undistributed income (loss) is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units based on provisions of the partnership agreement. Undistributed losses are not allocated to unvested restricted unit awards as they do not participate in net losses. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

Our general partner does not have an economic interest in the Partnership and, therefore, does not participate in the Partnership's net income.

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17. REPORTING SEGMENTS

“Midstream” and “Production” best describe the operating segments of the businesses that we separately report. The factors used to identify these reporting segments are based on the nature of the operations that are undertaken by each segment. The Midstream segment operates the gathering, processing and transportation of crude oil, natural gas and NGLs. The Production segment operates to produce crude oil and natural gas. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the Partnership because they are the segments (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Partnership’s chief operating decision maker (“CODM”) to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available. Operating segments are evaluated for their contribution to the Partnership’s consolidated results based on operating income, which is defined as segment operating revenues less expenses.

	Three Months Ended September 30,			
	2018		2017	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	\$ 166	\$ —	\$ 787	\$ —
Oil sales	2,848	—	3,061	—
Natural gas liquid sales	408	—	514	—
Gathering and transportation sales	—	1,582	—	14,234
Gathering and transportation lease revenues	—	13,148	—	—
Total segment revenues	3,422	14,730	4,362	14,234
Segment operating costs				
Lease operating expenses	1,597	308	1,585	150
Transportation operating expenses	—	3,061	—	2,661
Production taxes	292	—	340	—
Gain on sale of assets	(238)	—	(2,546)	—
Depreciation, depletion and amortization	1,202	5,305	1,756	5,143
Accretion expense	48	75	80	69
Total segment operating costs	2,901	8,749	1,215	8,023
Segment other income				
Earnings from equity investments	—	2,313	8	2,865
Total segment other income	—	2,313	8	2,865
Segment operating income	\$ 521	\$ 8,294	\$ 3,155	\$ 9,076

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	Nine Months Ended September 30,			
	2018		2017	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	\$ 865	\$ —	\$ 5,818	\$ —
Oil sales	7,894	—	22,520	—
Natural gas liquid sales	1,403	—	1,473	—
Gathering and transportation sales	—	4,931	—	39,621
Gathering and transportation lease revenues	—	38,634	—	—
Total segment revenues	10,162	43,565	29,811	39,621
Segment operating costs				
Lease operating expenses	4,993	890	9,957	642
Transportation operating expenses	—	8,979	—	8,989
Cost of sales	—	—	77	—
Production taxes	901	—	1,166	—
Gain on sale of assets	(2,626)	—	(2,546)	—
Depreciation, depletion and amortization	3,816	15,864	7,961	20,056
Asset impairments	—	—	4,688	—
Accretion expense	151	221	444	203
Total segment operating costs	7,235	25,954	21,747	29,890
Segment other income (loss)				
Earnings (loss) from equity investments	—	9,696	(101)	4,498
Total segment other income (loss)	—	9,696	(101)	4,498
Segment operating income	\$ 2,927	\$ 27,307	\$ 7,963	\$ 14,229

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
Reconciliation of segment operating income to net income (loss)				
Total production operating income	\$ 521	\$ 3,155	\$ 2,927	\$ 7,963
Total midstream operating income	8,294	9,076	27,307	14,229
Total segment operating income	8,815	12,231	30,234	22,192
General and administrative expense	(5,109)	(5,614)	(17,193)	(17,576)
Unit-based compensation expense	(155)	(631)	(2,940)	(1,951)
Interest expense, net	(2,786)	(2,215)	(8,165)	(5,994)
Other expense(a)	(352)	—	(1,876)	—
Net income (loss)	\$ 413	\$ 3,771	\$ 60	\$ (3,329)
(a)				

Other expense in 2017 excludes earnout rebate. As the rebate is reviewed by the CODM at the segment level, it was included in the Midstream segment operating costs.

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The following table summarizes the total assets and capital expenditures by operating segment based on the segment realignment as of September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018			Total
	Production	Midstream	Corporate (a)	
Other financial information				
Total assets	\$ 51,927	\$ 437,374	\$ 2,967	\$ 492,268
Capital expenditures(b)	\$ 169	\$ 4,403	\$ —	\$ 4,572

	December 31, 2017			Total
	Production	Midstream	Corporate (a)	
Other financial information				
Total assets	\$ 58,623	\$ 468,656	\$ 1,144	\$ 528,423
Capital expenditures(b)	\$ 441	\$ 46,452	\$ —	\$ 46,893

- (a) Corporate assets not reviewed by the CODM on a segment basis consists of cash, certain prepaid expenses, office furniture, and other assets.
- (b) Inclusive of capital contributions made to equity method investments.

18. VARIABLE INTEREST ENTITIES

The Partnership's investment in Carnero JV represents a variable interest entity ("VIE") that could expose the Partnership to losses. The amount of losses the Partnership could be exposed to from Carnero JV is limited to the capital investment of approximately \$117.7 million.

As of September 30, 2018, the Partnership had invested approximately \$123.8 million in Carnero JV and no debt has been incurred by Carnero JV. We have included this VIE in the equity investments long-term asset line on the balance sheet.

Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Partnership's maximum exposure to loss as of September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018	December 31, 2017
Acquisitions and capital investments	\$ 127,899	\$ 125,059
Earnings in equity investments	19,982	10,288
Distributions received	(30,204)	(11,632)
Maximum exposure to loss	\$ 117,677	\$ 123,715

19. SUBSEQUENT EVENTS

On November 8, 2018, the board of directors of our general partner declared a third quarter 2018 cash distribution on the Partnership's common units of \$0.15 per unit (\$0.60 per unit annualized) payable on November 30, 2018 to the holders of record on November 20, 2018. The Partnership also declared a third quarter distribution on the Class B Preferred Units and elected to pay the distribution in cash. Accordingly, the Partnership declared a cash distribution of \$0.28225 per Class B Preferred Unit payable on November 30, 2018 to holders of record on November 20, 2018.

On October 22, 2018, we completed the sale of certain non-operated production assets located in Louisiana for a purchase price of approximately \$1.3 million, after giving effect to customary closing adjustments. In addition, the buyer agreed to assume all obligations that arise on or after August 1, 2018.

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

The following discussion and analysis should be read in conjunction with the financial statements and the summary of significant accounting policies and notes included herein and in our most recent Annual Report on Form 10-K. The following discussion contains "Forward-Looking Statements" that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The "Forward-Looking Statements" are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these "Forward-Looking Statements." Please read "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are a growth-oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy-related assets in North America. The Partnership has ownership stakes in oil and natural gas gathering systems, natural gas pipelines and natural gas processing facilities, all located in the Western Eagle Ford in South Texas. Our assets include our wholly-owned Western Catarina Midstream gathering system, our wholly-owned Seco Pipeline, and a 50% interest in Carnero JV, a 50/50 joint venture operated by Targa that owns the Carnero Gathering Line, Raptor Gas Processing Facility, and Silver Oak II, and reversionary working interests and other production assets in Texas and Louisiana. On June 2, 2017, we changed our name to Sanchez Midstream Partners LP. Manager owns the general partner of SNMP and all of SNMP's incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol "SNMP."

How We Evaluate Our Operations

We evaluate our business on the basis of the following key measures:

- our throughput volumes on gathering systems upon acquiring those assets;
- our operating expenses; and
- our Adjusted EBITDA, a non-GAAP financial measure (for a reconciliation of Adjusted EBITDA to the most comparable GAAP financial measure please read "—Non-GAAP Financial Measures—Adjusted EBITDA").

Throughput Volumes

Upon the acquisition of Western Catarina Midstream, our management began to analyze our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within the dedicated areas in order to maintain or increase throughput volumes on Western Catarina Midstream. Our success in connecting additional wells is impacted by successful drilling activity by Sanchez Energy on the acreage dedicated to Western Catarina Midstream, our ability to secure volumes from Sanchez Energy from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure. Construction of the Seco Pipeline was completed in August 2017, and throughput volumes are dependent on gas processed at the Raptor Gas Processing Facility and demand for dry gas in markets in South Texas. Natural gas is currently being transported through the Seco Pipeline under the Seco Pipeline Transportation Agreement. Future throughput volumes on the pipeline are dependent on the continuation of this month-to-month agreement with Sanchez Energy, execution of a new agreement with Sanchez Energy or execution of an agreement with a third party.

Operating Expenses

Our management seeks to maximize Adjusted EBITDA, a non-GAAP financial measure, in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (which generally consists of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and

supplies expenses, among other items), compression expense, ad valorem taxes and other operating costs, some of which will be independent of our oil and natural gas production or the throughput volumes on the gathering system but fluctuate depending on the scale of our operations during a specific period.

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Non-GAAP Financial Measures—Adjusted EBITDA

To supplement our financial results and guidance presented in accordance with U.S. generally accepted accounting principles (“GAAP”), we use Adjusted EBITDA, a non-GAAP financial measure, in this quarterly report. We believe that non-GAAP financial measures are helpful in understanding our past financial performance and potential future results, particularly in light of the effect of various transactions effected by us. We define Adjusted EBITDA as net income (loss) adjusted by: (i) interest (income) expense, net, which includes interest expense, interest expense net (gain) loss on interest rate derivative contracts, and interest (income); (ii) income tax expense (benefit); (iii) depreciation, depletion and amortization; (iv) asset impairments; (v) accretion expense; (vi) (gain) loss on sale of assets; (vii) unit-based compensation expense; (viii) unit-based asset management fees; (ix) distributions in excess of equity earnings; (x) (gain) loss on mark-to-market activities; (xi) commodity derivatives settled early; (xii) (gain) loss on embedded derivatives; and (xiii) acquisition and divestiture costs.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by the board of directors of our general partner) the distributions that we would expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain or support a quarterly distribution or any increase in our quarterly distribution rates.

Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess: (i) the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and (iii) our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We believe that the presentation of Adjusted EBITDA provides useful information to investors in assessing our financial condition and results of operations. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss). Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income (loss). Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income (loss). Adjusted EBITDA should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following table sets forth a reconciliation of Adjusted EBITDA to net income (loss), its most directly comparable GAAP performance measure, for each of the periods presented (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income (loss)	\$ 413	\$ 3,771	\$ 60	\$ (3,329)
Adjusted by:				
Interest expense, net	2,786	2,215	8,165	5,994
Depreciation, depletion and amortization	6,507	6,899	19,680	28,017
Asset impairments	—	—	—	4,688
Accretion expense	123	149	372	647
Gain on sale of assets	(238)	(2,546)	(2,626)	(2,546)
Unit-based compensation expense	155	631	2,940	2,648
Unit-based asset management fees	2,365	2,103	7,291	6,478

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Distributions in excess of equity earnings	4,061	517	8,258	2,288
Loss on mark-to-market activities	2,183	7,000	8,614	1,173
Commodity derivatives settled early	—	(3,602)	—	(3,602)
Acquisition and divestiture costs	—	614	1,780	1,167
Adjusted EBITDA	\$ 18,355	\$ 17,751	\$ 54,534	\$ 43,623

Significant Operational Factors

- Throughput. During the three months ended September 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.8 MBbls/d of crude oil, 155.1 MMcf/d of natural gas and 11.0 MBbls/d of water. During the three months ended September 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 10.7 MBbls/d of crude oil, 162.5 MMcf/d of natural gas and 16.6 MBbls/d of water. During the three months ended September 30, 2018, Sanchez Energy transported average daily production through the Seco Pipeline of approximately 16.0 MMcf/d of natural gas. During the three and nine months ended September 30, 2017 there was an insignificant amount of natural gas transported through the Seco Pipeline. During the nine months ended September 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of

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approximately 12.1 MBbls/d of crude oil, 154.1 MMcf/d of natural gas and 10.4 MBbls/d of water. During the nine months ended September 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.2 MBbls/d of crude oil, 161.3 MMcf/d of natural gas and 11.2 MBbls/d of water. During the nine months ended September 30, 2018, Sanchez Energy transported average daily production through the Seco Pipeline of approximately 45.4 MMcf/d of natural gas.

- **Production.** Our production for the three months ended September 30, 2018, was 98 MBoe, or an average of 1,065 Boe/d, compared with approximately 188 MBoe, or an average of 2,043 Boe/d, for the three months ended September 30, 2017. Our production for the nine months ended September 30, 2018, was 357 MBoe, or an average of 1,308 Boe/d, compared with approximately 788 MBoe, or an average of 2,886 Boe/d, for the nine months ended September 30, 2017.
- **Capital Expenditures.** For the three months ended September 30, 2018, we spent approximately \$0.2 million in capital expenditures, related to the development of Western Catarina Midstream and \$0.1 million related to the development of the Seco Pipeline. For the three months ended September 30, 2017, we spent approximately \$7.5 million in capital expenditures, consisting of \$7.3 million related to the development of the Seco Pipeline and \$0.2 million related to the development of Western Catarina Midstream. For the nine months ended September 30, 2018, we spent approximately \$1.0 million in capital expenditures, related to the development of Western Catarina Midstream and \$0.6 million related to the development of the Seco Pipeline. For the nine months ended September 30, 2017, we spent approximately \$31.5 million in capital expenditures, consisting of \$29.0 million related to the development of the Seco Pipeline and \$2.5 million related to the development of Western Catarina Midstream.
- **Hedging Activities.** For the three months ended September 30, 2018, the non-cash mark-to-market loss for our commodity derivatives was approximately \$1.8 million, compared to a loss of \$7.0 million for the same period in 2017. For the nine months ended September 30, 2018, the non-cash mark-to-market loss for our commodity derivatives was approximately \$6.7 million, compared to a loss of \$1.2 million for the same period in 2017.

Recent Developments

On November 8, 2018, the board of directors of our general partner declared a third quarter 2018 cash distribution on the Partnership's common units of \$0.15 per unit (\$0.60 per unit annualized) payable on November 30, 2018 to the holders of record on November 20, 2018. The Partnership also declared a third quarter distribution on the Class B Preferred Units and elected to pay the distribution in cash. Accordingly, the Partnership declared a cash distribution of \$0.28225 per Class B Preferred Unit payable on November 30, 2018 to holders of record on November 20, 2018.

On October 22, 2018, we completed the sale of certain non-operated production assets located in Louisiana for a purchase price of approximately \$1.3 million, after giving effect to customary closing adjustments. In addition, the buyer agreed to assume all obligations that arise on or after August 1, 2018.

Results of Operations by Segment

Three months ended September 30, 2018 compared to three months ended September 30, 2017

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

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	Three Months Ended				
	September 30,				
	2018	2017	Variance		
Revenues:					
Gathering and transportation sales	\$ 1,582	\$ 14,234	\$ (12,652)	NM	(a)
Gathering and transportation lease revenues	13,148	—	13,148	NM	(a)
Total gathering and transportation sales	14,730	14,234	496	3	%
Operating expenses:					
Lease operating expenses	308	150	158	105	%
Transportation operating expenses	3,061	2,661	400	15	%
Depreciation and amortization	5,305	5,143	162	3	%
Accretion expense	75	69	6	9	%
Total operating expenses	8,749	8,023	726	9	%
Other income:					
Earnings from equity investments	2,313	2,865	(552)	(19)	%
Operating income	\$ 8,294	\$ 9,076	\$ (782)	(9)	%

(a) Variances deemed to be Not Meaningful “NM.” See Note 3 “Revenue Recognition” for explanation of the variance.

Gathering and transportation sales. During the three months ended September 30, 2018, Sanchez Energy transported average daily production through the Seco Pipeline of approximately 16.0 MMcf/d of natural gas. There were no meaningful quantities of throughput during the three months ended September 30, 2017 as the Seco Pipeline was not placed into service until August 2017.

Gathering and transportation lease revenues. On June 30, 2017, we amended the Western Catarina Midstream Gathering Agreement with Sanchez Energy to add an incremental infrastructure fee to be paid by SN Catarina based on water that was delivered through the gathering system through March 31, 2018. Following March 31, 2018, we have agreed with Sanchez Energy to continue the incremental infrastructure fee on a month-to-month basis. During the three months ended September 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.8 MBbls/d of crude oil, 155.1 MMcf/d of natural gas and 11.0 MBbls/d of water. During the three months ended September 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 10.7 MBbls/d of crude oil, 162.5 MMcf/d of natural gas and 16.6 MBbls/d of water.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, increased \$0.2 million to \$0.3 million for the three months ended September 30, 2018, compared to \$0.1 million during the same period in 2017. The increase was related to increased ad valorem taxes related to the Seco Pipeline.

Transportation operating expenses. Our operating expenses generally consist of equipment rentals, chemicals, treating, metering fees, permit and regulatory fees, labor, minor maintenance, tools, supplies, and pipeline integrity management expenses. Our transportation operating expenses increased \$0.4 million to \$3.1 million for the three months ended September 30, 2018, compared to \$2.7 million for the same period in 2017. This increase was a result of a full quarter of the Seco Pipeline being online compared to a partial quarter in 2017 due to the Seco Pipeline being placed into service during August 2017.

Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range

from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense increased \$0.2 million to \$5.3 million for the three months ended September 30, 2018, compared to \$5.1 million for the same period in 2017. This increase was a result of a full quarter of the Seco Pipeline being online compared to a partial quarter in 2017 due to the Seco Pipeline being placed into service during August 2017.

Earnings from equity investments. Earnings from equity investments decreased \$0.6 million to \$2.3 million for the three months ended September 30, 2018, compared to \$2.9 million for the same period in 2017. This decrease was the result of lower throughput for the Carnero JV during three months ended September 30, 2018.

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Production Operating Results

The following tables set forth the selected financial and operating data pertaining to the Production segment for the periods indicated (in thousands, except net production and average sales and average unit costs):

	Three Months Ended		Variance	
	2018	2017		
Revenues:				
Natural gas sales at market price	\$ 143	\$ 1,007	\$ (864)	(86) %
Natural gas hedge settlements	11	1,327	(1,316)	NM (a)
Natural gas mark-to-market activities	12	(1,555)	1,567	NM (a)
Natural gas total	166	779	(613)	(79) %
Oil sales at market price	5,302	4,517	785	17 %
Oil hedge settlements	(611)	3,989	(4,600)	NM (a)
Oil mark-to-market activities	(1,843)	(5,445)	3,602	NM (a)
Oil total	2,848	3,061	(213)	(7) %
NGL sales	408	514	(106)	(21) %
Miscellaneous expense	—	8	(8)	NM (a)
Total revenues	3,422	4,362	(940)	(22) %
Operating expenses:				
Lease operating expenses	1,597	1,585	12	1 %
Production taxes	292	340	(48)	(14) %
Gain on sale of assets	(238)	(2,546)	2,308	91 %
Depreciation, depletion and amortization	1,202	1,756	(554)	(32) %
Accretion expense	48	80	(32)	(40) %
Total operating expenses	2,901	1,215	1,686	139 %
Other income:				
Earnings from equity investments	—	8	(8)	NM (a)
Operating income	\$ 521	\$ 3,155	\$ (2,634)	(83) %

(a) Variances deemed to be Not Meaningful "NM."

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	Three Months Ended		Variance	
	2018	2017		
Net production:				
Natural gas (MMcf)	67	399	(332)	(83)%
Oil production (MBbl)	72	96	(24)	(25)%
NGLs (MBbl)	15	25	(10)	(40)%
Total production (MBoe)	98	188	(90)	(48)%
Average daily production (Boe/d)	1,065	2,043	(978)	(48)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	\$ 2.30	\$ 5.85	\$ (3.55)	(61)%
Natural gas price per Mcf without hedge settlements	\$ 2.13	\$ 2.52	\$ (0.39)	(15)%
Oil price per Bbl with hedge settlements	\$ 65.15	\$ 88.60	\$ (23.45)	(26)%
Oil price per Bbl without hedge settlements	\$ 73.64	\$ 47.05	\$ 26.59	57 %
NGL price per Bbl without hedge settlements	\$ 27.20	\$ 20.56	\$ 6.64	32 %
Total price per Boe with hedge settlements	\$ 53.60	\$ 60.39	\$ (6.79)	(11)%
Total price per Boe without hedge settlements	\$ 59.72	\$ 32.12	\$ 27.60	86 %
Average unit costs per Boe:				
Field operating expenses (a)	\$ 19.28	\$ 10.24	\$ 9.04	88 %
Lease operating expenses	\$ 16.30	\$ 8.43	\$ 7.87	93 %
Production taxes	\$ 2.98	\$ 1.81	\$ 1.17	65 %
Depreciation, depletion and amortization	\$ 12.27	\$ 9.34	\$ 2.93	31 %

(a) Field operating expenses include lease operating expenses and production taxes.

Production. For the three months ended September 30, 2018, 74% of our production was oil, 15% was NGLs and 11% was natural gas as compared to the three months ended September 30, 2017, where 51% of our production was oil, 13% was NGLs and 36% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2017 that were rich in natural gas. Combined production has decreased by 90 MBoe for the three months ended September 30, 2018, primarily due to the Briggs Divestiture and the Texas Production Divestiture.

Natural gas, NGLs and oil sales. Unhedged oil sales increased \$0.8 million, or 17%, to \$5.3 million for the three months ended September 30, 2018, compared to \$4.5 million for the same period in 2017. NGL sales decreased \$0.1 million, or 21%, to 0.4 million for the three months ended September 30, 2018, compared to \$0.5 million for the same period in 2017. Unhedged natural gas sales decreased \$0.9 million, or 86%, to \$0.1 million for the three months ended September 30, 2018, compared to \$1.0 million for the same period in 2017. Total decrease in oil, natural gas and NGL sales for the three months ended September 30, 2018 was primarily the result of the Briggs Divestiture and the Texas Production Divestiture.

Including hedges and mark-to-market activities, our total revenue decreased \$0.9 million for the three months ended September 30, 2018, compared to the same period in 2017. This decrease was primarily the result of a \$5.9 million decrease in settlements on oil and natural gas derivatives, a \$1.0 million decrease in natural gas and natural gas liquid sales, offset by a \$5.2 million increase in mark-to-market activities and a \$0.8 million increase in oil sales.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the three months ended September 30, 2018 to the three months ended September 30, 2017 (dollars in thousands, except average sales price):

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	Q3 2018 Production Volume	Q3 2017 Production Volume	Production Volume Difference	Q3 2017 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	67	399	(332)	\$ 2.52	\$ (837)
Oil (MBbl)	72	96	(24)	\$ 47.05	\$ (1,129)
Natural gas liquids (MBbl)	15	25	(10)	\$ 20.56	\$ (206)
Total oil equivalent (MBoe)	98	188	(90)	\$ 32.12	\$ (2,172)

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	Q3 2018 Average Sales Price	Q3 2017 Average Sales Price	Average Sales Price Difference	Q3 2018 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (MMcf)	\$ 2.13	\$ 2.52	\$ (0.39)	67	\$ (26)
Oil (MBbl)	\$ 73.64	\$ 47.05	\$ 26.59	72	\$ 1,914
Natural gas liquids (MBbl)	\$ 27.20	\$ 20.56	\$ 6.64	15	\$ 100
Total oil equivalent (MBoe)	\$ 59.72	\$ 32.12	\$ 27.60	98	\$ 1,988

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the three months ended September 30, 2018 by \$0.6 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the three months ended September 30, 2018, the non-cash mark-to-market loss was \$1.8 million, compared to a loss of \$7.0 million for the same period in 2017. The 2018 non-cash loss resulted from higher future expected oil prices on these derivative transactions. Cash settlements paid for our commodity derivatives were \$0.6 million for the three months ended September 30, 2018, compared to cash settlements received of \$5.3 million for the three months ended September 30, 2017.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, remained flat for the three months ended September 30, 2018 and 2017.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, natural gas and NGL production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the three months ended September 30, 2018 decreased \$0.6 million to \$1.2 million, compared to \$1.8 million for the same period in 2017. This decrease is primarily the result of the Briggs Divestiture and Texas Production Divestiture.

Impairment expense. For the three months ended September 30, 2018, and 2017 we did not record impairment charges.

Consolidated Earnings Results

The following table sets forth the reconciliation of segment operating income to net income (loss) for periods indicated (in thousands):

Three Months Ended
September 30,

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	2018	2017	Variance	
Reconciliation of segment operating income to net income				
Total production operating income	\$ 521	\$ 3,155	\$ (2,634)	(83) %
Total midstream operating income	8,294	9,076	(782)	(9) %
Total segment operating income	8,815	12,231	(3,416)	(28) %
General and administrative expense	(5,109)	(5,614)	505	(9) %
Unit-based compensation expense	(155)	(631)	476	(75) %
Interest expense, net	(2,786)	(2,215)	(571)	26 %
Other expense(b)	(352)	—	(352)	NM (a)
Net income	\$ 413	\$ 3,771	\$ (3,358)	(89) %

(a) Variances deemed to be Not Meaningful “NM.”

(b) Other expense in 2017 excludes earnout rebate. As the rebate is reviewed by the CODM at the segment level, it was included in the Midstream segment operating costs.

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General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, decreased to \$5.3 million for the three months ended September 30, 2018, compared to \$6.2 million for the same period in 2017. This decrease was primarily driven by a decrease in unit-based compensation as well as a decrease in salaries and wages.

Interest expense, net. Interest expense increased \$0.6 million, to \$2.8 million for the three months ended September 30, 2018, compared to \$2.2 million for the same period in 2017. This increase was the result of borrowings under our Credit Agreement, primarily to fund development of the Seco Pipeline.

Nine months ended September 30, 2018 compared to nine months ended September 30, 2017

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

	Nine Months Ended September 30,				
	2018	2017	Variance		
Revenues:					
Gathering and transportation sales	\$ 4,931	\$ 39,621	\$ (34,690)	NM	(a)
Gathering and transportation lease revenues	38,634	—	38,634	NM	(a)
Total gathering and transportation sales	43,565	39,621	3,944	10	%
Operating costs:					
Lease operating expenses	890	642	248	39	%
Transportation operating expenses	8,979	8,989	(10)	—	
Depreciation and amortization	15,864	20,056	(4,192)	(21)	%
Accretion expense	221	203	18	9	%
Total operating expenses	25,954	29,890	(3,936)	(13)	%
Other income:					
Earnings from equity investments	9,696	4,498	5,198	116	%
Operating income	\$ 27,307	\$ 14,229	\$ 13,078	92	%

(a) Variances deemed to be Not Meaningful “NM.” See Note 3 “Revenue Recognition” for explanation of the variance.

Gathering and transportation sales. During the nine months ended September 30, 2018, Sanchez Energy transported average daily production through the Seco Pipeline of approximately 45.4 MMcf/d of natural gas. There were no meaningful quantities of throughput during the nine months ended September 30, 2017 as the Seco Pipeline was not placed into service until August 2017.

Gathering and transportation lease revenues. On June 30, 2017, we amended the Western Catarina Midstream Gathering Agreement with Sanchez Energy to add an incremental infrastructure fee to be paid by SN Catarina based on water that was delivered through the gathering system through March 31, 2018. Following March 31, 2018, we have agreed with Sanchez Energy to continue the incremental infrastructure fee on a month-to-month basis. During the nine months ended September 30, 2018, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 12.1 MBbls/d of crude oil, 154.1 MMcf/d of natural gas and 10.4 MBbls/d of

water. During the nine months ended September 30, 2017, Sanchez Energy transported average daily production through Western Catarina Midstream of approximately 11.2 MBbls/d of crude oil, 161.3 MMcf/d of natural gas and 11.2 MBbls/d of water.

Lease operating expenses. Lease operating expenses, which includes ad valorem taxes, increased \$0.3 million to \$0.9 million for the nine months ended September 30, 2018 compared to \$0.6 million during the same period in 2017. The increase was related to increased ad valorem taxes related to the Seco Pipeline.

Transportation operating expenses. Our operating expenses generally consist of equipment rentals, chemicals, treating, metering fees, permit and regulatory fees, labor, minor maintenance, tools, supplies, and pipeline integrity management expenses. Our transportation operating expenses remained flat for the nine months ended September 30, 2018 and 2017.

Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense decreased \$4.2 million to \$15.9 million

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for the nine months ended September 30, 2018, compared to \$20.1 million during the same period in 2017. This decrease was the result of certain midstream assets becoming fully depreciated in June 2017.

Earnings from equity investments. Earnings from equity investments increased \$5.2 million to \$9.7 million for the nine months ended September 30, 2018, compared to \$4.5 million for the same period in 2017. This increase was the result of benefitting from earnings in the Raptor Gas Processing Facility for the full nine months ended September 30, 2018.

Production Operating Results

The following tables set forth the selected financial and operating data pertaining to the Production segment for the periods indicated (in thousands, except net production and average sales and costs):

	Nine Months Ended		Variance		
	September 30, 2018	2017			
Revenues:					
Natural gas sales at market price	\$ 838	\$ 5,413	\$ (4,575)	(85)	%
Natural gas hedge settlements	37	2,624	(2,587)	NM	(a)
Natural gas mark-to-market activities	(10)	(2,127)	2,117	NM	(a)
Natural gas total	865	5,910	(5,045)	(85)	%
Oil sales	16,004	15,433	571	4	%
Oil hedge settlements	(1,383)	6,133	(7,516)	NM	(a)
Oil mark-to-market activities	(6,727)	954	(7,681)	NM	(a)
Oil total	7,894	22,520	(14,626)	(65)	%
NGL sales	1,403	1,473	(70)	(5)	%
Miscellaneous expense	—	(92)	92	NM	(a)
Total revenues	10,162	29,811	(19,649)	(66)	%
Operating costs:					
Lease operating expenses	4,993	9,957	(4,964)	(50)	%
Cost of sales	—	77	(77)	(100)	%
Production taxes	901	1,166	(265)	(23)	%
Gain on sale of assets	(2,626)	(2,546)	(80)	(3)	%
Depreciation, depletion and amortization	3,816	7,961	(4,145)	(52)	%
Asset impairments	—	4,688	(4,688)	(100)	%
Accretion expense	151	444	(293)	(66)	%
Total operating expenses	7,235	21,747	(14,512)	(67)	%
Other income:					
Loss from equity investments	—	(101)	101	NM	(a)
Operating income	\$ 2,927	\$ 7,963	\$ (5,036)	(63)	%

(a) Variances deemed to be Not Meaningful "NM."

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	Nine Months Ended		Variance	
	September 30, 2018	2017		
Net production:				
Natural gas (MMcf)	373	2,302	(1,929)	(84) %
Oil production (MBbl)	236	326	(90)	(28) %
NGLs (MBbl)	59	78	(19)	(24) %
Total production (MBoe)	357	788	(431)	(55) %
Average daily production (Boe/d)	1,308	2,886	(1,578)	(55) %
Average sales prices:				
Natural gas price per Mcf with hedge settlements	\$ 2.35	\$ 3.49	\$ (1.14)	(33) %
Natural gas price per Mcf without hedge settlements	\$ 2.25	\$ 2.35	\$ (0.10)	(4) %
Oil price per Bbl with hedge settlements	\$ 61.95	\$ 66.15	\$ (4.20)	(6) %
Oil price per Bbl without hedge settlements	\$ 67.81	\$ 47.34	\$ 20.47	43 %
NGL price per Bbl without hedge settlements	\$ 23.78	\$ 18.88	\$ 4.90	26 %
Total price per Boe with hedge settlements	\$ 47.34	\$ 39.44	\$ 7.90	20 %
Total price per Boe without hedge settlements	\$ 51.11	\$ 28.32	\$ 22.79	80 %
Average unit costs per Boe:				
Field operating expenses (a)	\$ 16.51	\$ 14.12	\$ 2.39	17 %
Lease operating expenses	\$ 13.99	\$ 12.64	\$ 1.35	11 %
Production taxes	\$ 2.52	\$ 1.48	\$ 1.04	70 %
Depreciation, depletion and amortization	\$ 10.69	\$ 10.10	\$ 0.59	6 %

(a) Field operating expenses include lease operating expenses and production taxes.

Production. For the nine months ended September 30, 2018, 66% of our production was oil, 17% was NGLs and 17% was natural gas as compared to the nine months ended September 30, 2017, where 41% of our production was oil, 10% was NGLs and 49% was natural gas. The production mix between the periods has shifted to a higher oil production as a result of multiple asset divestitures in 2017 that were rich in natural gas. Combined production has decreased by 431 MBoe for the nine months ended September 30, 2018, primarily due to the Briggs Divestiture, the Oklahoma Production Divestiture and the Texas Production Divestiture.

Natural gas, NGLs and oil sales. Unhedged oil sales increased \$0.6 million, or 4%, to \$16.0 million for the nine months ended September 30, 2018, compared to \$15.4 million for the same period in 2017. NGL sales decreased \$0.1 million, or 5%, to \$1.4 million for the nine months ended September 30, 2018, compared to \$1.5 million for the same period in 2017. Unhedged natural gas sales decreased \$4.6 million, or 85%, to \$0.8 million for the nine months ended September 30, 2018, compared to \$5.4 million for the same period in 2017. Total decrease in oil, natural gas and NGL sales for the nine months ended September 30, 2018 was primarily the result of the Briggs Divestiture, the Oklahoma Production Divestiture and the Texas Production Divestiture.

Including hedges and mark-to-market activities, our total revenue decreased \$19.6 million for the nine months ended September 30, 2018, compared to the same period in 2017. This decrease was primarily the result of a \$5.6 million decrease in mark-to-market activities, a \$10.1 million decrease in settlements on oil and natural gas derivatives, a \$4.6 million decrease in natural gas sales, offset by an \$0.6 million increase in oil sales.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the nine months ended September 30, 2018 to the nine months ended September 30, 2017 (dollars in thousands, except average sales price):

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	2018 Production Volume	2017 Production Volume	Production Volume Difference	2017 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (MMcf)	373	2,302	(1,929)	\$ 2.35	\$ (4,533)
Oil (MBbl)	236	326	(90)	\$ 47.34	\$ (4,261)
NGLs (MBbl)	59	78	(19)	\$ 18.88	\$ (359)
Total oil equivalent (MBoe)	357	788	(431)	\$ 28.32	\$ (9,153)

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	2018 Average Sales Price	2017 Average Sales Price	Average Sales Price Difference	2018 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (MMcf)	\$ 2.25	\$ 2.35	\$ (0.10)	373	\$ (37)
Oil (MBbl)	\$ 67.81	\$ 47.34	\$ 20.47	236	\$ 4,832
NGLs (MBbl)	\$ 23.78	\$ 18.88	\$ 4.90	59	\$ 289
Total oil equivalent (MBoe)	\$ 51.11	\$ 28.32	\$ 22.79	357	\$ 5,084

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the nine months ended September 30, 2018 by \$1.8 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the nine months ended September 30, 2018, the non-cash mark-to-market loss was \$6.7 million, compared to a loss of \$1.2 million for the same period in 2017. The 2018 non-cash loss resulted from higher future expected oil prices on these derivative transactions. Cash settlements paid for our commodity derivatives were \$1.3 million for the nine months ended September 30, 2018, compared to cash settlements received of \$8.8 million for the nine months ended September 30, 2017.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses. Lease operating expenses, which include ad valorem taxes, decreased \$5.0 million, or 50%, to \$5.0 million for the nine months ended September 30, 2018, compared to \$10.0 million during the same period in 2017. The decreased lease operating expenses for the comparative periods were primarily the result of the Briggs Divestiture, the Oklahoma Production Divestiture and the Texas Production Divestiture.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, natural gas and NGL production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the nine months ended September 30, 2018 was \$3.8 million compared to \$8.0 million for the same period in 2017. This decrease is primarily the result of the Briggs Divestiture, the Oklahoma Production Divestiture and the Texas Production Divestiture.

Impairment expense. For the nine months ended September 30, 2018, we did not record impairment charges. For the nine months ended September 30, 2017, we recorded non-cash charges of \$4.7 million to impair certain of our producing oil and natural gas properties in Texas.

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Consolidated Earnings Results

The following table sets forth the reconciliation of segment operating income to net income (loss) for periods indicated (in thousands):

	Nine Months Ended		Variance		
	September 30, 2018	2017			
Reconciliation of segment operating income to net income (loss)					
Total production operating income	\$ 2,927	\$ 7,963	\$ (5,036)	(63)	%
Total midstream operating income	27,307	14,229	13,078	92	%
Total segment operating income	30,234	22,192	8,042	36	%
General and administrative expense	(17,193)	(17,576)	383	(2)	%
Unit-based compensation expense	(2,940)	(1,951)	(989)	51	%
Interest expense, net	(8,165)	(5,994)	(2,171)	36	%
Other expense(b)	(1,876)	—	(1,876)	NM	(a)
Net income (loss)	\$ 60	\$ (3,329)	\$ 3,389	(102)	%

(a) Variances deemed to be Not Meaningful “NM.”

(b) Other expense in 2017 excludes earnout rebate. As the rebate is reviewed by the CODM at the segment level, it was included in the Midstream segment operating costs.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit-based compensation expense, increased to \$20.1 million for the nine months ended September 30, 2018, compared to \$19.5 million for the same period in 2017. This increase was primarily driven by an increase in unit-based compensation of \$1.0 million and offset by a decrease other general and administrative expenses of \$0.4 million during the nine months ended September 30, 2018.

Interest expense, net. Interest expense increased \$2.2 million to \$8.2 million for the nine months ended September 30, 2018, compared to \$6.0 million for the same period in 2017. This increase was the result of borrowings under our Credit Agreement, primarily to fund capital projects in our joint ventures with Targa and development of the Seco Pipeline.

Liquidity and Capital Resources

As of September 30, 2018, we had approximately \$2.3 million in cash and cash equivalents and \$26.0 million available for borrowing under the Credit Agreement in effect on such date. During the three months ended September 30, 2018, we paid approximately \$2.5 million in cash for interest on borrowings under our Credit Agreement, of which approximately \$27.0 thousand was related to the commitment fee on undrawn commitments. For the nine months ended September 30, 2018, we paid approximately \$7.3 million in cash for interest on borrowings under our Credit Agreement, of which approximately \$61.2 thousand was related to the commitment fee on undrawn commitments.

Our capital expenditures during the three and nine months ended September 30, 2018 were funded with cash on hand. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional limited partner units. We expect that the combination of these capital resources will be adequate to meet our short-term working capital requirements, long-term capital expenditures program and expected quarterly cash distributions.

We expect that our future cash requirements relating to working capital, maintenance capital expenditures and quarterly cash distributions to our partners will be funded from cash flows internally generated from our operations. Our expansion capital expenditures will be funded by borrowings under our Credit Agreement or from potential capital market transactions. However, there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our current debt level, planned levels of capital expenditures, operating expenses or any cash distributions that we may make to unitholders.

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto. The Credit Agreement provides a maximum commitment of \$500.0 million and has a maturity date of March 31, 2020. Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that we own, as well as various security and pledge agreements among the Partnership, certain of its subsidiaries and the administrative agent.

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The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of \$15.0 million, which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was \$200.0 million. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is generally equal to the rolling four quarter Adjusted EBITDA of our midstream operations, together with the amount of distributions received from Carnero JV multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of our lenders. As of September 30, 2018, the borrowing base under the Credit Agreement was \$310.0 million, with an elected commitment amount of \$210.0 million.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) LIBOR plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) ABR plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus (iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

- Current assets to current liabilities for at least 1.0 to 1.0 at all times;
- Senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the adjusted EBITDA of our midstream operations equals or exceeds one-third of total Adjusted EBITDA or 4.0 to 1.0 if the adjusted EBITDA of our midstream operations is less than one-third of total adjusted EBITDA; and
- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of

default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At September 30, 2018, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt under the Credit Agreement could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

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Sources of Debt and Equity Financing

As of September 30, 2018, the elected commitment amount under our Credit Agreement was set at \$210.0 million, and we had \$184.0 million of debt outstanding under the facility, leaving us with \$26.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of September 30, 2018. Our Credit Agreement matures on March 31, 2020.

Open Commodity Hedge Positions

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties. In August 2017, we repositioned certain of our crude oil and natural gas hedges in anticipation of the sale of the Texas Production Assets and, in the process, received \$3.6 million in net cash from the counterparties on those hedges.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. All of our derivatives are currently collateralized by the assets securing our Credit Agreement and therefore currently do not require the posting of cash collateral. This is significant since we are able to lock in sales prices on a substantial amount of our expected future production without posting cash collateral based on price changes prior to the hedges being cash settled.

The following tables as of September 30, 2018, summarize, for the periods indicated, our hedges currently in place through December 31, 2020. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps— West Texas Intermediate (WTI)

	Three Months Ended (volume in Bbls)		September 30,		December 31,		Total			
	March 31,	June 30,	September 30,	December 31,	Total	Average	Average	Average		
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2018	—	\$ —	—	\$ —	—	\$ —	59,704	\$ 59.84	59,704	\$ 59.84
2019	62,528	\$ 60.41	59,552	\$ 60.44	57,024	\$ 60.48	54,824	\$ 60.52	233,928	\$ 60.46
2020	52,776	\$ 53.50	50,960	\$ 53.50	49,224	\$ 53.50	47,624	\$ 53.50	200,584	\$ 53.50
									494,216	

MTM Fixed Price Basis Swaps— NYMEX (Henry Hub)

Three Months Ended (volume in MMBtu)

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	March 31,		June 30,		September 30,		December 31,		Total	Average
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Price
2018	—	\$ —	—	\$ —	—	\$ —	117,040	\$ 3.00	117,040	\$ 3.00
2019	119,832	\$ 2.85	115,784	\$ 2.85	112,032	\$ 2.85	108,552	\$ 2.85	456,200	\$ 2.85
2020	105,104	\$ 2.85	102,008	\$ 2.85	99,136	\$ 2.85	96,200	\$ 2.85	402,448	\$ 2.85
									975,688	

Operating Cash Flows

We had net cash flows provided by operating activities for the nine months ended September 30, 2018 of \$52.1 million, compared to net cash flow provided by operating activities of \$36.6 million for the same period in 2017. This increase was primarily related to expedited collection of accounts receivable-related entities which lead to additional cash inflows of \$6.4 million for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017. Further, operating cash flows increased as a result of higher average commodity process between the periods of \$5.1 million, and a return from equity investment greater than equity earnings for the period of \$7.9 million.

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Our operating cash flows are subject to many variables, the most significant of which is the volume of oil and natural gas transported through our midstream assets, volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future operating cash flows will depend on oil and natural gas transported through our midstream assets, as well as the market prices of oil and natural gas and our hedging program.

Investing Activities

We had net cash flows provided by investing activities for the nine months ended September 30, 2018 of \$1.2 million, consisting primarily of \$6.2 million related to proceeds from the sale of oil and natural gas properties. This was offset by outflows of \$4.8 million related to pipeline construction and contributions to equity investments.

We had net cash flows used in investing activities for the nine months ended September 30, 2017 of \$32.6 million, consisting of \$30.3 million related to midstream activities, including pipeline construction, and contributions to Carnero Processing and Carnero Gathering totaling \$10.5 million. These outflows were offset by \$7.0 million related to proceeds from sales of oil and natural gas properties and final settlement of an acquisition.

Financing Activities

Net cash flows used in financing activities was \$51.4 million for the nine months ended September 30, 2018. During the nine months ended September 30, 2018, we distributed \$24.5 million and \$20.8 million to Class B Preferred Unit holders and common unit holders, respectively, during the same period. Additionally, we paid \$0.1 million in offering costs and repaid borrowings of \$7.0 million.

Net cash flows used in financing activities was \$4.6 million for the nine months ended September 30, 2017. During the nine months ended September 30, 2017, we had borrowings under our Credit Agreement of \$45.5 million and proceeds from issuance of common units of \$1.3 million. We distributed \$22.8 million and \$18.5 million to Class B Preferred Unit holders and common unit holders, respectively, during the same period. Additionally, we paid \$0.6 million in offering costs and repaid \$9.5 million of borrowings.

Off-Balance Sheet Arrangements

As of September 30, 2018, we had no off-balance sheet arrangements with third parties, and we maintained no debt obligations that contained provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the generation of substantially all of our midstream business segment revenues from a single customer, Sanchez Energy, the sale of oil and natural gas and our use of derivatives. Through September 30, 2018, we have not suffered any significant losses with our counterparties as a result of non-performance.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally

accepted in the United States of America. The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

As of September 30, 2018, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017, which was filed with the SEC on March 12, 2018. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read Part 1. Item 1. Note 2. "Basis of Presentation and Summary of Significant Accounting Policies" to the condensed consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

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New Accounting Pronouncements

See Part 1. Item 1. Note 2. “Basis of Presentation and Summary of Significant Accounting Policies” to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Principal Executive Officer and the Principal Financial Officer of the general partner of SNMP have evaluated the effectiveness of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of September 30, 2018 (the “Evaluation Date”). Based on such evaluation, the Principal Executive Officer and the Principal Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and is accumulated and communicated to our management, including the Principal Executive Officer and the Principal Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The adoption of ASC 606, Revenue from Contracts with Customers, required the implementation of new controls and the modification of certain accounting processes related to revenue recognition. The impact of these changes was not material to our internal control over financial reporting.

Part II—Other Information

Item 1. Legal Proceedings

From time to time we may be the subject of lawsuits and claims arising in the ordinary course of business. Management cannot predict the ultimate outcome of such lawsuits or claims. Management does not currently expect the outcome of any of the known claims or proceedings to individually or in the aggregate have a material adverse effect on our results of operations or financial condition.

Item 1A. Risk Factors

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

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

In connection with providing services under the Services Agreement for the second quarter 2018, the Partnership issued 224,342 common units to Manager on September 10, 2018. See Note 13 “Related Party Transactions” for additional information related to the Services Agreement. The issuance of these common units was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof as a transaction by an issuer not involving a public offering.

No common units were purchased in the third quarter 2018.

Item 3. Defaults Upon Senior Securities

None.

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Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the exhibit index below and are incorporated herein by reference.

EXHIBIT INDEX

Exhibit

Number Description

31.1* Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1** Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2** Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS* XBRL Instance Document

101.SCH* XBRL Schema Document

101.CAL* XBRL Calculation Linkbase Document

101.LAB* XBRL Label Linkbase Document

101.PRE* XBRL Presentation Linkbase Document

101.DEF* XBRL Definition Linkbase Document

*Filed herewith.

**Furnished herewith.

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SIGNATURES

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

SANCHEZ MIDSTREAM PARTNERS LP

(REGISTRANT)

By: Sanchez Midstream Partners GP LLC, its general partner

Date: November 9, 2018

By /s/ Charles C. Ward

Charles C. Ward

Chief Financial Officer and Secretary

(Duly Authorized Officer and Principal Financial Officer)

