Sanchez Production Partners LP
Form 10-Q
August 12, 2016
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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 June 30, 2016

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 Production Partners LP

(Exact name of registrant as specified in its charter)

Delaware	11-3742489
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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)

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 and posted on its corporate Web site, if any, 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 and post 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. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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 August 11, 2016: Approximately 4,279,517 units.

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Cautionary Note Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995 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; acquisition strategy; financing strategy; 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 and processing agreements; future operating results; future capital expenditures; and plans, objectives, expectations, forecasts, outlook and intentions. All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potentia "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. 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 utilize the services, personnel and other assets of the sole member of our general partner ("Manager") pursuant to existing services agreements;
· our ability to make, maintain and grow distributions;
· the timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids ("NGLs"), natural gas and related commodities;
· the realized benefits of our transactions with Sanchez Energy Corporation ("SN"), including with respect to the Palmetto escalating working interest acquisition, acquisition of Western Catarina midstream assets and Carnero Gathering Transaction referred to herein;
· the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise;
· the ability of our customers to meet their drilling and development plans on a timely basis or at all and perform under gathering and processing agreements;
· our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
· the credit worthiness and performance of our counterparties, including financial institutions, operating partners and other parties;
· 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;
· 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 availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
· 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

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

- the extent to which our crude oil and natural gas properties operated by others are operated successfully and economically;
- the use of competing energy sources and the development of alternative energy sources;
- unexpected results of litigation filed against us;
- 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 Quarterly Report on Form 10 Q and in our other public filings with the Securities and Exchange Commission (the “SEC”).

Management cautions all readers that the forward-looking statements contained in this Quarterly Report on 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. 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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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Operations

(In thousands, except unit data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues				
Natural gas sales	$ 600	$ 3,642	$ 4,275	$ 10,216
Oil sales	(2,756)	639	2,587	5,603
Natural gas liquids sales	244	500	520	886
Gathering and transportation sales	14,258	—	28,133	—
Total revenues	12,346	4,781	35,515	16,705
Expenses:				
Operating expenses:				
Lease operating expenses	4,178	5,358	9,151	10,258
Transportation operating expenses	3,014	—	6,068	—
Cost of sales	63	125	193	330
Production taxes	326	583	547	953
General and administrative	4,978	3,351	10,697	10,906
Unit compensation expense	1,091	395	1,529	2,387
Gain on sale of assets	—	(54)	—	(113)
Depreciation, depletion and amortization	6,129	3,079	13,317	6,199
Asset impairments	—	862	1,309	83,727
Accretion expense	315	264	630	517
Total operating expenses	20,094	13,963	43,441	115,164
Other expense (income)				
Interest expense	1,103	1,122	2,002	1,768
Gain on embedded derivatives	(6,898)	—	(13,192)	—
Other expense (income)	(1)	37	(61)	100
Total other expenses (income)	(5,796)	1,159	(11,251)	1,868
Total expenses	14,298	15,122	32,190	117,032
Net income (loss)	(1,952)	(10,341)	3,325	(100,327)
Less:				
Preferred unit paid-in-kind distributions	—	(524)	—	(524)
Preferred unit distributions	(8,750)	—	(17,500)	—
Preferred unit amortization	(6,505)	—	(13,772)	—
Net loss attributable to common unitholders	$ (17,207)	$ (10,865)	$ (27,947)	$ (100,851)
Loss per unit				
Net loss per unit prior to conversion(1)				

Class A units - Basic and diluted	$ —	$ —	$ —	$ (0.38)
Class B units - Basic and diluted	$ —	$ —	$ —	$ (0.31)
Weighted Average Units Outstanding prior to conversion(1)				
Class A units - Basic and diluted	—	—	—	48,451
Class B units - Basic and diluted	—	—	—	2,879,163
Net loss per unit after conversion(1)				
Common units - Basic and diluted	$ (4.37)	$ (3.49)	$ (8.38)	$ (32.37)
Weighted Average Units Outstanding after conversion(1)				
Common units - Basic and diluted	3,935,297	3,113,428	3,333,482	3,087,431

(1) Amounts adjusted for 1-for-10 reverse split completed August 3, 2015. See Note 14.

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

ASSETS	June 30, 2016 (Unaudited)	December 31, 2015
Current assets		
Cash and cash equivalents	$ 1,203	$ 6,571
Restricted cash	—	600
Accounts receivable	1,663	2,461
Accounts receivable - related entities	7,351	1,515
Prepaid expenses	2,159	744
Fair value of derivative instruments	8,650	21,010
Total current assets	21,026	32,901
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	731,977	732,088
Gathering and transportation assets	147,695	147,479
Material and supplies	1,056	1,056
Less accumulated depreciation, depletion, amortization, accretion and impairments	(662,099)	(653,569)
Oil and natural gas properties and equipment, net	218,629	227,054
Other assets		
Intangible assets, net	192,824	199,741
Fair value of derivative instruments	6,054	10,008
Other non-current assets	1,524	1,596
Total assets	$ 440,057	$ 471,300
LIABILITIES AND PARTNERS' CAPITAL		
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 1,780	$ 7,288
Accounts payable and accrued liabilities - related entities	3,669	1,035
Royalties payable	499	689
Total current liabilities	5,948	9,012
Other liabilities		
Asset retirement obligation	19,515	20,364
Embedded derivatives	179,885	193,077
Long-term debt, net of debt issuance costs	107,091	104,909
Total other liabilities	306,491	318,350
Total liabilities	312,439	327,362
Commitments and contingencies (See Note 10)		
Mezzanine equity		
Class B preferred units, 19,444,445 units issued and outstanding as of June 30, 2016 and December 31, 2015	186,264	172,111

Partners' capital		
Class A preferred units, zero units issued and outstanding as of June 30, 2016 and 11,409,131 units issued and outstanding as of December 31, 2015	—	17,112
Common units, 4,279,517 units issued and outstanding as of June 30, 2016 and 3,240,812 units issued and outstanding as of December 31, 2015	(58,646)	(45,285)
Total partners' deficit	(58,646)	(28,173)
Total liabilities and partners' capital	$ 440,057	$ 471,300

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(unaudited)

	Six Months Ended June 30, 2016		2015	
Cash flows from operating activities:				
Net income (loss)	$	3,325	$	(100,327)
Adjustments to reconcile net income (loss) to cash provided by operating activities:				
Depreciation, depletion and amortization		7,262		6,011
Amortization of intangible assets		6,917		188
Asset impairments		1,309		83,727
Amortization of debt issuance costs		246		324
Accretion expense		630		517
Revisions to asset retirement obligation included in DD&A		(862)		—
Equity earnings in affiliate		(12)		48
Gain from disposition of property and equipment		(9)		(113)
Bad debt expense		35		122
Total mark-to-market on commodity derivative contracts		3,736		1,066
Cash mark-to-market settlements on commodity derivative contracts		13,028		8,950
Unit-based compensation programs		1,952		2,388
Gain on embedded derivative		(13,192)		—
Costs for plug and abandon activities		(86)		—
Changes in Operating Assets and Liabilities:				
		313		1,721

Decrease in accounts receivable		
Increase in accounts receivable - related entities	(5,836)	(1,582)
Increase in accounts payable - related entities	2,634	—
(Increase) decrease in prepaid expenses	(1,414)	408
(Increase) decrease in other assets	659	(981)
(Decrease) increase in accounts payable/accrued liabilities	(3,128)	2,788
Decrease in royalties payable	(190)	(399)
Net cash provided by operating activities	17,317	4,856
Cash flows from investing activities:		
Cash paid for acquisitions	—	(81,378)
Development of oil and natural gas properties	(2,269)	(1,056)
Proceeds from sale of assets	16	344
Distributions from equity affiliate	—	15
Net cash used in investing activities	(2,253)	(82,075)
Cash flows from financing activities:		
Proceeds from issuance of preferred units	—	17,375
Payments for offering costs	(87)	(810)
Proceeds from issuance of debt	2,000	106,000
Repayment of debt	—	(42,500)
Issuance of common units	—	52
Repurchase of common units under repurchase program	(2,948)	—
Units tendered by employees for tax withholdings	(140)	(618)
Distributions to unitholders	(3,025)	
Class B preferred unit cash distributions	(16,168)	—
Debt issuance costs	(64)	(1,294)
Net cash provided by (used in) financing activities	(20,432)	78,205
Net increase (decrease) in cash and cash equivalents	(5,368)	986
	6,571	4,238

Cash and cash equivalents, beginning of period				
Cash and cash equivalents, end of period	$	1,203	$	5,224
Supplemental disclosures of cash flow information:				
Change in accrued capital expenditures	$	(1,609)	$	(149)
Acquisition of oil and natural gas properties in exchange for common units		—		2,000
Cash paid during the period for interest		(1,732)		(1,154)
Cash paid during the period for income taxes		—		(2)

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Members' Equity/Partners' Capital

(In thousands, except unit data)

(Unaudited)

	Class A Units		Class B Units		Class A Preferred Units		Common Units		Total
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Equity/
nbers' Equity, ember 31, 2014	48,451	$ 1,930	2,879,258	$ 104,893	—	$ —	—	$ —	$ 106,8
s tendered by oyees for tax holding	—	—	(1,557)	(21)	—	—	—	—	(21)
oss (January March 5th)	—	(18)	—	(905)	—	—	—	—	(923)
nbers' Equity, ch 5, 2015	48,451	1,912	2,877,701	103,967	—	—	—	—	105,8
s A Units erted to mon units upon ed partnership ersion	(48,451)	(1,912)	—	—	—	—	58,729	1,912	—
s B Units erted to mon units upon ed partnership ersion	—	—	(2,877,701)	(103,967)	—	—	2,877,701	103,967	—
s tendered by oyees for tax holding	—	—	—	—	—	—	(32,269)	(597)	(597)
-based pensation rams	—	—	—	—	—	—	472,972	2,454	2,454
ate placement lass A Preferred s, net of ing costs of million	—	—	—	—	10,859,375	16,550	—	—	16,55
eficial ersion feature lass A preferred	—	—	—	—	—	(863)	—	863	—
	—	—	—	—	834,989	1,425	—	(1,425)	—

erred unit -in-kind ibutions									
ance of mon units	—	—	—	—	—	—	6,865	193	193
mon units ed via unit rchase program	—	—	—	—	—	—	(143,185)	(2,223)	(2,22
mon units ed for isition of erties	—	—	—	—	—	—	105,263	2,000	2,000
mon units ved and retired cquisition of erties	—	—	—	—	—	—	(105,263)	(1,065)	(1,06
distributions	—	—	—	—	—	—	—	(1,219)	(1,21
ributions - s B preferred	—	—	—	—	—	—	—	(14,012)	(14,0
oss (March 6th cember 31st)	—	—	—	—	—	—	—	(136,133)	(136,
er's Capital, ember 31, 2015	—	$ —	—	$ —	11,694,364	$ 17,112	3,240,813	$ (45,285)	$ (28,1
s tendered by oyees for tax holding	—	—	—	—	—	—	(12,227)	(140)	(140)
s forfeited by oyees	—	—	—	—	—	—	(2,000)	—	—
-based pensation rams	—	—	—	—	—	—	67,627	1,952	1,952
ance of mon units	—	—	—	—	—	—	58,363	771	771
s A Preferred s converted to mon units	—	—	—	—	(11,694,364)	(17,112)	1,169,441	17,112	—
mon units ed via unit back program	—	—	—	—	—	—	(242,500)	(2,948)	(2,94
distributions mmon unit ers	—	—	—	—	—	—	—	(3,025)	(3,02
ributions - s B preferred	—	—	—	—	—	—	—	(30,408)	(30,4
ncome	—	—	—	—	—	—	—	3,325	3,325
er's Capital, 30, 2016	—	$ —	—	$ —	—	$ —	4,279,517	$ (58,646)	$ (58,6

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ PRODUCTION PARTNERS LP AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BUSINESS

Organization

Sanchez Production Partners LP, a Delaware limited partnership (together with our consolidated subsidiaries "SPP", "we", "us", "our" or the "Partnership"), is a publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy production assets. SPP completed its initial public offering on November 20, 2006, as Constellation Energy Partners LLC ("CEP" or the "Company"). We have entered into a shared services agreement (the "Services Agreement") with SP Holdings, LLC (the "Manager"), the sole member of our general partner, pursuant to which the Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance and acquisition, disposition and financing services. On March 6, 2015, the Company's unitholders approved the conversion of Sanchez Production Partners LLC to a Delaware limited partnership and the name was changed to Sanchez Production Partners LP. The Manager owns the general partner of SPP and all of SPP's incentive distribution rights. Our common units are currently listed on the NYSE MKT under the symbol "SPP."

Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("SN") and entered into a 15-year gathering and processing agreement with SN. In July 2016, we sold a significant portion of our oil and gas properties in the Mid-Continent region.

As a result of the acquisition of midstream assets from SN and the disposition of our oil and gas properties located in the Mid-Continent region, our historical financial statements (including those in this Form 10-Q) will differ substantially from our future financial statements beginning with the quarter ending December 31, 2015, principally because a significant portion of our revenues now come from the long-term, fee-based gathering and processing agreement with SN rather than from oil and natural gas production.

2. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These unaudited condensed consolidated financial statements include the accounts of SPP and our wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation. We conduct our business activities as two operating segments: (1) the exploration and production of oil and natural gas and (2) the midstream business, which includes the Catarina gathering system. Our management evaluates performance based on these two business segments.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the Securities and Exchange Commission ("SEC"). Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with accounting principles generally accepted in the United States ("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 the Company and our subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2015, which was filed with the SEC on March 30, 2016.

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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 March 2016, the FASB issued Accounting Standards Update ("ASU") No. 2016-09 "Improvements to Employee Share-Based Payment Accounting," effective for annual and interim periods for public companies beginning after December 15, 2016, with a cumulative-effect and prospective approach to be used for implementation. ASU 2016-09 changes several aspects of the accounting for share-based payment award transactions including accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, minimum statutory tax withholding requirements and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. 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 Accounting Standards Update No. 2016-02 "Leases (Topic 842)," effective for annual and interim periods for public companies beginning after December 15, 2018, with a modified retrospective approach to be used for implementation. ASU 2016-02 updates 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. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In September 2015, the FASB issued ASU No. 2015-16, "Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments," effective for annual and interim periods beginning after December 15, 2015. ASU 2015-16 eliminates the requirement for an acquirer to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. During the first quarter of 2016, the Company adopted ASU 2015-16. Adoption of this guidance did not have a material impact on our consolidated financial statements and footnote disclosures.

In July 2015, the FASB issued ASU No. 2015-11, "Simplifying the Measurement of Inventory," effective for annual and interim periods beginning after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost and net realizable value. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

In April 2015, the FASB issued ASU No. 2015-03, "Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs." This guidance is intended to more closely align the presentation of debt issuance costs under U.S. GAAP with the presentation requirements under International Financial Reporting Standards. Under this new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as a separate asset as previously presented. This guidance is effective for fiscal years and interim periods beginning after December 15, 2015. In August 2015, the FASB issued ASU 2015-15, "Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements." The guidance in ASU 2015-03 does not address debt issuance costs related to line-of-credit arrangements. ASU 2015-15 states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. During the first quarter of 2016, the Company adopted ASU 2015-03 and ASU 2015-15 retrospectively to the comparable periods in this Form 10-Q. Adoption of this guidance affected the balance sheets as of December 31, 2015 as follows (in thousands):

Decrease in Long term debt, net of debt issuance costs of approximately $2,091

Decrease in Debt issuance costs (Other Assets) of approximately $2,091

In February 2015, the FASB issued ASU No. 2015-02, “Consolidation (Topic 810): Amendments to the Consolidation Analysis” to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (“VIEs”) or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. These provisions are effective for annual reporting periods beginning after December 15, 2015, and interim periods within those annual periods, with early adoption permitted. During the first quarter of 2016, the Company adopted ASU 2015-02. Adoption of this guidance did not have a material impact on our consolidated financial statements and footnote disclosures.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” 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 guidance is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is not permitted. The guidance may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

Reclassifications

Certain reclassifications have been made to the prior period to conform to the current period presentation. These reclassifications had no effect on total unitholders’ equity, net income or net cash provided by or used in operating, investing or financing activities. In accordance with ASU No. 2015-03 and ASU No. 2015-15, debt issuance costs are to be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as a separate asset as previously presented. As such, debt issuance costs, net of amortization, at December 31, 2015 of $2.1 million have been reclassified from other assets to other liabilities, effectively eliminating the debt issuance cost line and reducing long-term debt in the balance sheet.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to 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 oil, natural gas and natural gas liquids (“NGLs”); future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of commodity 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 estimates and judgment. 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.

Significant Accounting Policies

Our significant accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2015.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash. Checks-in-transit are included in our consolidated balance sheets as accounts payable or as a reduction of cash, depending on the type of bank account the checks were drawn on. There were no checks-in-transit reported in accounts payable as of June 30, 2016 or December 31, 2015.

Restricted Cash

As of June 30, 2016, we had no restricted cash. As of December 31, 2015, we had approximately $0.6 million of restricted cash held in escrow that related to a vendor dispute that remained in the escrow account until the dispute was resolved in March 2016.

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Accounts Receivable, Net

Our accounts receivable are primarily from purchasers of oil and natural gas, gathering and transportation sales, and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted. As of June 30, 2016 and December 31, 2015, we had an allowance for doubtful accounts receivable of $0.1 million and $0.4 million, respectively.

3. ACQUISITIONS

Eagle Ford Acquisition

On March 31, 2015, we completed an acquisition of wellbore interests in certain producing oil and natural gas properties in Gonzales County, Texas (the "Eagle Ford properties," and such acquisition, the "Eagle Ford acquisition") located in the Eagle Ford Shale in Gonzales County, Texas from SN for a purchase price of $85 million, subject to normal and customary closing adjustments. The effective date of the transaction was January 1, 2015. The acquisition included initial conveyed working interests and net revenue interests for each property that escalate on January 1 for each year from 2016 through 2019, at which point, SPP's interests in the Eagle Ford properties will stay constant for the remainder of the respective lives of the assets.

The adjusted purchase price of $83.4 million was funded at closing with net proceeds from the private placement of 10,625,000 newly created Class A Preferred Units, which were issued for a cash purchase price of $1.60 per unit, resulting in gross proceeds to SPP of $17.0 million, the issuance of 1,052,632 common units (approximately 105,263 common units after adjusting for a reverse unit split) to SN, borrowings under the Partnership's Credit Agreement (as defined in Note 6, "Long-Term Debt"), and available cash. The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved developed reserves	$ 72,889
Facilities	8,002
Fair value of hedges assumed	3,408
Fair value of assets acquired	84,299
Asset retirement obligations	(877)
Ad valorem tax liability	(44)
Fair value of net assets acquired	$ 83,378

Western Catarina Midstream Acquisition

On October 14, 2015, we completed an acquisition of midstream assets located in Western Catarina, in the Eagle Ford Shale in South Texas from SN for a purchase price of $345.8 million, subject to normal and customary closing adjustments (the "Western Catarina Midstream acquisition"). The purchase price was funded at closing with net proceeds from the sale of Class B Preferred Units to Stonepeak Catarina Holdings LLC, an affiliate of Stonepeak Infrastructure Partners ("Stonepeak") and available cash. Additionally, as a result of the Western Catarina Midstream acquisition, we repurchased 105,263 common units previously held by a subsidiary of SN.

The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Fixed assets	$ 142,887
Contractual customer relationships	201,888
Purchase of SPP common units from SN	1,065
Fair value of assets acquired	$ 345,840

Pro Forma Operating Results (Unaudited)

The following unaudited pro forma combined financial information for the six months ended June 30, 2016 and 2015 reflect the consolidated results of operations of the Partnership as if the Western Catarina Midstream and Eagle Ford acquisitions and related

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financings had occurred on January 1, 2015. The pro forma information includes adjustments primarily for revenues and expenses from the acquired properties, depreciation, depletion, amortization and accretion, interest expense and debt issuance cost amortization for acquisition debt, amortization of customer contract intangible assets acquired and paid-in-kind units issued in connection with the Class A Preferred Units.

The unaudited pro forma combined financial statements give effect to the events set forth below:

- The Western Catarina Midstream acquisition completed on October 14, 2015.
  - Issuance of Class B Preferred Units to finance the Western Catarina Midstream acquisition.
- Repurchase of common units issued to finance a portion of the Eagle Ford acquisition as a part of the Western Catarina Midstream acquisition, and the related effect on net income (loss) per common unit.
- The Eagle Ford acquisition completed on March 31, 2015.
- The increase in borrowings under the Credit Agreement to finance a portion of the Eagle Ford acquisition, and the related adjustments to interest expense.
- Issuance of common units to finance a portion of the Eagle Ford acquisition and the related effect on net income (loss) per common unit (in thousands, except per unit amounts).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues	$ 12,346	$ 15,375	$ 35,515	$ 41,121
Net income (loss) attributable to common unitholders	$ (17,630)	$ (23,087)	$ (27,923)	$ (124,982)
Net income (loss) per unit prior to conversion				
Class A units - Basic and diluted	$ —	$ —	$ —	$ (23.87)
Class B units - Basic and diluted	$ —	$ —	$ —	$ (18.99)
Net income (loss) per unit after conversion				
Common units - Basic and diluted	$ (4.48)	$ (5.39)	$ (7.13)	$ (15.37)

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Partnership would have reported had the Western Catarina Midstream and Eagle Ford acquisitions and related financings been completed as of the date set forth in this unaudited pro forma combined financial information and should not be taken as indicative of the Partnership's future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Post-Acquisition Operating Results

The amounts of revenue and excess of revenues over direct operating expenses included in the Partnership's condensed consolidated statements of operations for the three and six months ended June 30, 2016, for the Eagle Ford and Western Catarina Midstream acquisitions are shown in the table that follows. Direct operating expenses include lease operating expenses and production and ad valorem taxes (in thousands):

	Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
Revenues	$ 16,485	$ 32,157
Excess of revenues over direct operating expenses	$ 12,324	$ 23,822

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4. 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. This category includes those derivative instruments that can be valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative 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). The valuation models used to value derivatives associated with the Partnership's oil and natural gas production are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although third party quotes are utilized to assess the reasonableness of the prices and valuation techniques, there is not sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

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.

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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 June 30, 2016 (in thousands):

	Fair Value Measurements at June 30, 2016				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at June 30, 2016
Derivative assets	$ —	$ 14,704	$ —	$ —	$ 14,704
Derivative liabilities	—	—	—	—	—
Embedded derivative	—	—	(179,885)		(179,885)
Total net assets	$ —	$ 14,704	$ (179,885)	$ —	$ (165,181)

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, 2015 (in thousands):

	Fair Value Measurements at December 31, 2015				
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Netting Cash and Collateral	Fair Value at December 31, 2015
Derivative assets	$ —	$ 31,018	$ —	$ —	$ 31,018
Derivative liabilities	—	—	—	—	—
Embedded derivative	—	—	(193,077)		(193,077)
Total net assets	$ —	$ 31,018	$ (193,077)	$ —	$ (162,059)

As of June 30, 2016 and December 31, 2015, 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 Accounting Standards Codification ("ASC") 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. The fair values of oil and natural gas properties and asset retirement obligations 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 include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) 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. Our purchase price allocation for the Eagle Ford acquisition is presented in Note 3, ''Acquisitions." Fair value of oil and natural gas properties are presented in Note 7, "Oil and Natural Gas Properties." A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 8, ''Asset Retirement Obligation.''

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. 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 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 6, "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 derivatives as of June 30, 2016. We prioritize the use of the highest level inputs available in determining fair value such that fair value

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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.

Embedded Derivative – The Partnership consummated a contract for the sale of preferred units in October 2015 which contained provisions that must be bifurcated from the contract and valued as a derivative. The embedded derivative is valued through the use of a Monte Carlo model which utilizes observable inputs, the Partnership's unit prices at various timelines, as well as unobservable inputs related to the weighted probabilities of certain redemption scenarios. As a result, we have classified the fair value measurements of our embedded derivative as Level 3 inputs. The Partnership has marked this derivative to market as of June 30, 2016, and incurred an approximate $13.2 million gain as a result. The gain is the result in the reduction in fair value of the embedded derivative due to the decrease in unit price.

The fair value of the Partnership's embedded derivative classified as Level 3 as of June 30, 2016 was $179.9 million. Changes in the unobservable inputs will impact the fair value measurement of the Partnership's embedded derivative contract.

The following table sets forth a reconciliation of changes in the fair value of the Partnership's embedded derivative classified as Level 3 in the fair value hierarchy for the six months ended June 30, 2016 and the year ended December 31, 2015 (in thousands):

	Significant Unobservable Inputs (Level 3)	
	June 30, 2016	December 31, 2015
Beginning balance	$ (193,077)	$ —
Initial fair value of embedded derivative - bifurcated from mezzanine equity	—	(183,095)
Gain (loss) on embedded derivative	13,192	(9,982)
Ending balance	$ (179,885)	$ (193,077)
Gain (loss) included in earnings related to derivatives still held as of June 30, 2016, and December 31, 2015	$ 13,192	$ (9,982)

5. 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 transactions are normally price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. 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 ASC 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 and liquids sales in the condensed consolidated statements of operations.

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As of June 30, 2016, 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)

	For the Quarter Ended June 30, 2016 (volume in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2016					106,483	$ 73.95	100,525	$ 74.10	207,008	$ 74.03
2017	57,953	$ 64.80	54,554	$ 64.80	51,570	$ 64.80	48,926	$ 64.80	213,003	$ 64.80
2018	56,798	$ 65.40	54,197	$ 65.40	51,851	$ 65.40	49,709	$ 65.40	212,555	$ 65.40
2019	52,760	$ 65.65	50,784	$ 65.65	48,960	$ 65.65	47,264	$ 65.65	199,768	$ 65.65
									832,334	

Fixed Price Swaps—NYMEX (Henry Hub)

	For the Quarter Ended June 30, 2016 (volume in Mcfs)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2016					998,394	$ 4.14	963,327	$ 4.14	1,961,721	$ 4.14
2017	80,563	$ 3.52	75,829	$ 3.52	71,672	$ 3.52	67,984	$ 3.52	296,048	$ 3.52
2018	79,042	$ 3.58	75,404	$ 3.58	72,115	$ 3.58	69,122	$ 3.58	295,683	$ 3.58
2019	73,432	$ 3.62	70,648	$ 3.62	68,088	$ 3.62	65,720	$ 3.62	277,888	$ 3.62
									2,831,340	

The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the six months ended June 30, 2016 and the year ended December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Beginning fair value of commodity derivatives	$ 31,018	$ 22,829
Net gains (losses) on crude oil derivatives	(3,568)	22,410
Net gains (losses) on natural gas derivatives	(168)	6,148
Net settlements on derivative contracts:		
Crude oil	(8,052)	(13,191)
Natural gas	(4,526)	(7,178)
Ending fair value of commodity derivatives	$ 14,704	$ 31,018

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

		Amount of Gain (Loss) in Income			
	Location of Gain	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Derivative Type	in Income	2016	2015	2016	2015
Commodity – Mark-to-Market	Oil sales	$ (6,260)	$ (5,555)	$ (3,568)	$ (2,912)
Commodity – Mark-to-Market	Natural gas sales	(1,466)	(342)	(168)	1,848
		$ (7,726)	$ (5,897)	$ (3,736)	$ (1,064)

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with three 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. As of June 30, 2016 and December 31, 2015, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

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Hedges Novated in the Eagle Ford Acquisition

As a part of the Eagle Ford acquisition, we received by novation from the seller certain hedges covering approximately 90%, 85%, 85% and 80% of estimated 2016, 2017, 2018 and 2019 oil and natural gas production from the acquired assets, respectively. The counterparty for the hedges is a lender in the Partnership's Credit Agreement. The Partnership is responsible for all future periodic settlements of these transactions. As of June 30, 2016, the fair value of the hedges assumed resulted in an $8.9 million asset in our condensed consolidated balance sheet.

Embedded Derivative

The Partnership consummated a contract for the sale of preferred units in October 2015 which contained provisions that must be bifurcated from the contract and valued as a derivative. The embedded derivative is valued through the use of a Monte Carlo model which utilizes observable inputs, the Partnership's unit prices at various timelines, as well as unobservable inputs related to the weighted probabilities of certain redemption scenarios. The Partnership has marked this derivative to market as of June 30, 2016, and incurred an approximate $13.2 million gain as a result.

The following table sets forth a reconciliation of the changes in fair value of the Partnership's embedded derivative for the quarters ended June 30, 2016 and the year ended December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Beginning fair value of embedded derivative	$ (193,077)	$ —
Initial fair value of embedded derivative - bifurcated from mezzanine equity	—	(183,095)
Gain (loss) on embedded derivative	13,192	(9,982)
Ending fair value of embedded derivative	$ (179,885)	$ (193,077)

6. 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 facility provides a maximum commitment of $500,000,000 and has a maturity date of March 31, 2020. Borrowings under the credit facility 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 and certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the credit facility is limited to the borrowing base for our oil and natural gas properties and our midstream assets. Borrowings under the credit facility are available for direct investment in oil and gas properties, acquisitions, and working capital and general business purposes. The credit facility has a sub-limit of $15,000,000 which may be used for the issuance of letters of credit. The initial borrowing base under the credit facility was $200,000,000. 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 equal to the rolling four quarter EBITDA of our midstream operations multiplied by 4.75 for the second quarter of 2016 and 4.5 thereafter. 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.

On May 19, 2016, and June 1, 2016, respectively, SPP received notification that its lenders completed a semi-annual review of the RBL Component and quarterly review of the Midstream Component of the partnership’s borrowing base pursuant to the terms of its credit facility. Based on these reviews, the borrowing base has been established at $195.7 million.

At our election and as of June 30, 2016, interest for borrowings under the credit facility are determined by reference to (i) the London interbank rate ("LIBOR") plus an applicable margin between 1.75% and 2.75% per annum based on utilization or (ii) a domestic bank rate ("ABR") plus an applicable margin between 0.75% and 1.75% per annum based on utilization plus (iii) a commitment fee between 0.375% and 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 facility 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 facility 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 facility and exercise other rights and remedies.

The credit facility 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 facility, 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 facility 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 June 30, 2016, we were in compliance with the financial covenants contained in the credit facility. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our credit facility 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 facility, such that our outstanding debt 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.

During the first quarter of 2016, the Company adopted ASU 2015-03 retrospectively to the comparable periods in this Form 10-Q. Adoption of this guidance affected the balance sheets as of December 31, 2015 as follows (in thousands):

Decrease in Long term debt, net of debt issuance costs of approximately $2,091

Decrease in Debt issuance costs, net (Other Assets) of approximately $2,091

Debt Issuance Costs

As of June 30, 2016, our unamortized debt issuance costs were $1.9 million. These costs are amortized to interest expense in our consolidated statement of operations over the life of our credit facility. At December 31, 2015, our unamortized debt issuance costs were $2.1 million.

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7. OIL AND NATURAL GAS PROPERTIES

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

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

	June 30, 2016	December 31, 2015
Oil and natural gas properties and related equipment (successful efforts method)		
Property costs		
Proved property	$ 731,435	$ 731,548
Unproved property	41	39
Land	501	501
Total property costs	731,977	732,088
Materials and supplies	1,056	1,056
Total	733,033	733,144
Less: Accumulated depreciation, depletion, amortization and impairments	(657,259)	(652,167)
Oil and natural gas properties and equipment, net	$ 75,774	$ 80,977

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

	June 30, 2016	December 31, 2015
Gathering and transportation assets		
Catarina midstream assets	$ 147,695	$ 147,479
Less: Accumulated depreciation, depletion, amortization	(4,840)	(1,402)
Total gathering and transportation assets	$ 142,855	$ 146,077

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. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed 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 June 30, 2016	2015	Six Months Ended June 30, 2016	2015
DD&A of oil and natural gas-related assets	$ 942	$ 3,079	$ 2,962	$ 6,199
DD&A of gathering and transportation related assets	1,729	—	3,438	—
Total DD&A	2,671	3,079	6,400	6,199
Asset impairments	—	862	1,309	83,727
Total	$ 2,671	$ 3,941	$ 7,709	$ 89,926

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 third-party 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.

For the three months ended June 30, 2016, we did not record non-cash impairment charges. For the six months ended June 30, 2016, we recorded non-cash charges of $1.3 million to impair our producing oil and natural gas properties in Texas and Louisiana acquired prior to the Eagle Ford acquisition. For the three and six months ended June 30, 2015, we recorded non-cash charges of $0.9 million and $83.7 million, respectively, to impair the value of our Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties acquired prior to the Eagle Ford acquisition. The carrying values of the impaired proved properties were reduced to fair value of $75.8 million as of June 30, 2016, estimated using inputs characteristic of a Level 3 fair value measurement.

Asset Retirement Obligation. As described in Note 8, estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved developed reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Exploration and Dry Hole Costs. Exploration and dry hole costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs and the impairment, amortization and abandonment associated with leases on our unproved properties. All such costs on oil and natural gas properties relating to unsuccessful exploratory wells are charged to expense as incurred. We recorded no exploration or dry hole costs for the six months ended June 30, 2016 or 2015.

8. 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. Subsequently, the ARC is depreciated using a systematic and rational method over the asset's useful life. 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 property balance.

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

	June 30, 2016	December 31, 2015
Asset retirement obligation, beginning balance	$ 20,364	$ 17,031
Liabilities added from acquisitions	—	3,634
Liabilities added from drilling	—	—
Sold	—	(58)
Revisions to cost estimates	(1,393)	(1,156)
Settlements	(86)	(186)
Accretion expense	630	1,099
Asset retirement obligation, ending balance	$ 19,515	$ 20,364

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. As of June 30, 2016 and December 31, 2015, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs. During the year ended December 31, 2015, revisions were made to the ARO liability based on recent costs incurred on abandoned wells, which were lower on average than originally projected.

9. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes $192.3 million related to the customer contract with SN that was agreed to as part of the Western Catarina Midstream acquisition. Pursuant to the 15-year agreement, SN tenders all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through the gathering system, 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. The remaining $0.5 million of the intangible assets balance is comprised of marketing contracts from the 2007 Newfield acquisition which are being amortized using the straight-line method over the 10 year life of the agreement.

Amortization expense for the six months ended June 30, 2016 and 2015 was $6.9 million and $0.2 million, respectively. Intangible assets as of June 30, 2016 and December 31, 2015 are detailed below (in thousands):

	June 30, 2016	December 31, 2015
Beginning balance	$ 199,741	$ 1,033
Additions	—	201,888
Amortization	(6,917)	(3,180)
Ending balance	$ 192,824	$ 199,741

10. COMMITMENTS AND CONTINGENCIES

We did not have any material commitments and contingencies as of June 30, 2016.

11. RELATED PARTY TRANSACTIONS

We are controlled by our general partner. The sole member of our general partner is Manager, which has no officers. In May 2014, we entered into the Services Agreement with Manager pursuant to which Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. In connection with providing services under the Services Agreement, Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, is paid in cash unless Manager elects for such fee to be paid in our equity. The Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless both Manager and the Company provide notice to terminate the agreement. During the six months ended June 30, 2016, we expensed $3.0

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million to Manager pursuant to the Services Agreement. During the six months ended June 30, 2015, we paid $2.4 million to Manager under the Services Agreement, which included a prepayment of $0.5 million that was applied to the third quarter of 2015.

Manager utilizes SOG to provide the services under the Services Agreement. In May 2014, we entered into a Contract Operating Agreement with SOG pursuant to which SOG either provides services to operate, develop and produce our oil and natural gas properties or engages a third-party operator to do so, other than with respect to our properties in the Mid-Continent Region. We also have entered into the Geophysical Seismic Data Use License Agreement with SOG pursuant to which SOG provides us a non-exclusive, royalty-free license to use seismic, geophysical and geological information relating to our oil and natural gas properties that is proprietary to SOG and not restricted by agreements that SOG has with landowners or seismic data vendors.

The Partnership has entered into a Firm Gathering and Processing Agreement with SN for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas will be dedicated for gathering by Catarina Midstream, LLC (“Catarina Midstream”). In addition, for the first five years of the Gathering Agreement, SN Catarina, LLC will be required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments.

As of June 30, 2016 and December 31, 2015, the Partnership had a net receivable from related parties of $7.4 million and $1.5 million, respectively, which are included in “Accounts receivable – related entities” in the condensed consolidated balance sheets. As of June 30, 2016 and December 31, 2015, the Partnership also had a net payable from related parties of $3.7 million and $1.0 million, respectively. The net receivables/payable as of June 30, 2016 and December 31, 2015 consist primarily of revenues receivable from oil and natural gas production, offset by costs associated with that production and obligations for general and administrative costs.

On March 31, 2015, the Partnership and SN entered into a Purchase and Sale Agreement for the Eagle Ford acquisition for total consideration of $85.0 million. After $1.4 million in normal and customary closing adjustments, consideration paid at closing consisted of $81.6 million cash paid by us to SN and 105,263 of our common units issued to SN with an aggregate consideration value of $2,000,000. All 105,263 common units issued as consideration for the Eagle Ford acquisition were repurchased in connection with the Western Catarina Midstream acquisition in October 2015. See further discussion of the transaction in Note 3, “Acquisitions.”

In October 2015, the Partnership and SN consummated the Western Catarina Midstream acquisition for total consideration of approximately $345.8 million in cash, subject to closing and post-closing adjustments. Concurrently with the signing of the Western Catarina Midstream acquisition purchase and sale agreement, we entered into a 15-year gas gathering and processing agreement with SN. For the six months ended June 30, 2016, SN paid us approximately $23.2 million pursuant to the terms of the gathering and processing agreement. See further discussion of the transaction in Note 3, “Acquisitions.”

On July 5, 2016, the Partnership entered into an agreement with SN and SN Midstream, LLC, a wholly-owned subsidiary of SN, to purchase 50% of the issued and outstanding membership interests in Carnero Gathering, LLC (see further discussion in Note 16, “Subsequent Events”).

12. UNIT-BASED COMPENSATION

Prior to our conversion to a Delaware limited partnership on March 6, 2015, we granted restricted common unit awards to certain employees in Texas under the 2009 Omnibus Incentive Compensation Plan (the “Omnibus Plan”). The Omnibus Plan provided for a variety of unit-based and performance-based awards, including unit options, restricted units, unit grants, notional units, unit appreciation rights, performance awards and other unit-based awards. Additionally, prior to March 6, 2015, we granted restricted common unit awards to certain field employees in Kansas and Oklahoma and to certain employees in Texas under our previous Long-Term Incentive Plan (the "Previous LTIP").

After our conversion to a limited partnership, both the Omnibus Plan and the Previous LTIP had no outstanding units remaining. Effective March 6, 2015, the Omnibus Plan was amended and restated and renamed the Sanchez Production Partners LP Long-Term Incentive Plan (the "LTIP") and the Previous LTIP was merged into the LTIP. Restricted unit activity under the Omnibus Plan, the Previous LTIP, and the LTIP during the period, after adjusting for the 1-for-10 reverse split completed on August 3, 2015, is presented in the following table:

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	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2015	361,357	$ 14.18
Granted	67,627	10.35
Vested	(86,041)	11.54
Returned/Cancelled	(14,227)	15.81
Outstanding at June 30, 2016	328,716	$ 14.01

During the year ended December 31, 2015, the Partnership issued 346,925 restricted common units (34,693 restricted common units after adjusting for reverse unit split) pursuant to the LTIP to the directors of the Partnership's general partner that vested immediately on the date of the grant. The unit based compensation expense for the awards were based on their grant date fair values. In March 2015, officers were granted a total of 1,025,641 restricted common units (102,564 restricted common units after adjusting for the reverse unit split) that were due upon request, of which 769,231 restricted common units (76,923 restricted common units after adjusting for reverse unit split) were vested and delivered at the request of the officers, net of 322,692 restricted common units (32,269 restricted common units after adjusting for reverse unit split) that were returned to the plan for settlement of taxes associated with the vesting. Furthermore, on December 1, 2015, the board of directors of our general partner approved the grant of 335,715 restricted units pursuant to the LTIP to employees, service providers, and executive officers that which are set to vest pro-rata over a three-year period. In April 2016, officers were granted a total of 67,627 restricted common units that were vested and delivered.

As of June 30, 2016, 213,273 common units remain available for future issuance to participants under the LTIP.

13. DISTRIBUTIONS TO UNITHOLDERS

From the second quarter of 2009 through the second quarter of 2015, we did not pay distributions on our common units. Starting in the third quarter of 2015, the board of directors of our general partner declared distributions of Class A Preferred Units on August 10, 2015 and November 10, 2015 to holders as of August 14, 2015 and November 16, 2015, respectively. A total of 549,756 paid-in-kind units were distributed for the year ended December 31, 2015. On November 30, 2015, we paid a cash distribution with respect to the quarter ended September 30, 2015 in the amount of $0.400 per common unit. On February 9, 2016, we announced that the board of directors of our general partner approved a cash distribution of $0.406 per common unit for the fourth quarter of 2015. The Partnership also declared a fourth quarter 2015 paid-in-kind distribution of 2.5% on its Class A preferred units and a fourth quarter prorated cash distribution of $0.3815 on its Class B preferred units. The distributions were paid on February 29, 2016 to unitholders of record on February 19, 2016. On May 10, 2016, we announced that the board of directors of our general partner approved a cash distribution of $0.4121 per common unit and $0.450 per Class B preferred unit for the first quarter of 2016. The distributions were paid on May 31, 2016 to unitholders of record on May 20, 2016. All Class A preferred Units were converted to common units on a one to one basis at March 31, 2016; as such, no paid-in-kind distributions were made on Class A Preferred Units for the second quarter of 2016. On August 10, 2016, we announced that the board of directors of our general partner approved a cash distribution of $0.4183 per common unit and $0.450 per Class B preferred unit for the second quarter of 2016. The distributions are payable on August 31, 2016 to unitholders of record on August 22, 2016.

14. MEMBERS' EQUITY/PARTNERS' CAPITAL

Outstanding Units

As of June 30, 2016, we had no Class A Preferred Units outstanding, 19,444,445 Class B Preferred Units outstanding, and 4,279,517 common units outstanding.

Common Unit Issuances

On March 31, 2016, the Partnership converted all remaining outstanding Class A Preferred Units into common units of the Partnership on a one for one basis, adjusted for the 1-for-10 unit split in August 2015.

In April 2015, we entered into an at-the-market sales agreement with MLV & Co. LLC to sell from time-to-time up to $100 million of our common units, with any proceeds from such sales to be used for general limited partnership purposes. We did not sell any common units during the six months ended June 30, 2016.

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On August 3, 2015, the Partnership effected a 1-for-10 reverse split on its common units, pursuant to which common unitholders received one common unit for every ten common units held at the close of trading on August 3, 2015. All fractional units created by the reverse split were rounded to the nearest whole unit. Each unitholder received at least one unit. Post-split units of the Partnership began trading on August 4, 2015. Immediately prior to the reverse unit split, there were 31,495,506 common units of the Partnership issued and outstanding, with a per unit closing trading price on the NYSE MKT on August 3, 2015 of $1.55. Immediately after the reverse unit split, the number of issued and outstanding common units of the Partnership decreased to 3,149,551, not inclusive of common units required by DTCC due to the rounding up of fractional units at the beneficial level, and the per unit opening trading price on the NYSE MKT was $15.50.

Preferred Unit Issuance

Class A Preferred Unit Offerings: On March 31, 2015, the Partnership entered into a Class A Preferred Unit Purchase Agreement with the purchasers named on Schedule A thereto (collectively, the “March Purchasers”), pursuant to which the Partnership sold, and the March Purchasers purchased, 10,625,000 of the Partnership’s newly created Class A Preferred Units (the “Class A Preferred Units”) in a privately negotiated transaction for an aggregate cash purchase price of $1.60 per Class A Preferred Unit resulting in gross proceeds to the Partnership of $17 million. The Partnership used the net proceeds of $17 million from this transaction, together with common units issued to SN, borrowings under our credit facility, and available cash on hand, to pay the consideration for the Eagle Ford acquisition.

Additionally, on April 15, 2015, the Partnership entered into a Class A Preferred Unit Purchase Agreement with the purchasers named on Schedule A thereto (collectively, the “April Purchasers”), pursuant to which the Partnership sold, and the April Purchasers purchased, 234,375 of the Partnership’s Class A Preferred Units in a privately negotiated transaction for an aggregate cash purchase price of $1.60 per Class A Preferred Unit resulting in gross and net proceeds to the Partnership of $375,000. The Partnership used the proceeds for general working capital purposes.

On March 31, 2016, the Partnership converted all remaining outstanding Class A Preferred Units into common units of the Partnership on a one for one basis, adjusted for 1-for-10 unit split in August 2015.

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 Catarina Holdings LLC (the “October Purchaser”), the Partnership sold and the October Purchaser 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 $350,000,010. The Partnership used the net proceeds to pay a portion of the consideration for the Western Catarina Midstream acquisition, along with the payment to the October Purchaser of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

Under the terms of our partnership agreement, commencing with the quarter ended on December 31, 2015, the Class B Preferred Units will 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 paid-in-kind units (4.0% per annum). In the event the Partnership does not raise at least $75,000,000 through the issuance of additional common units prior to September 30, 2016 (with the conversion of the Class A Preferred Units of the Partnership counting toward such amount), the cash portion of the distribution rate will increase by 4.0% per annum until the end of the quarter in which such issuance is consummated. 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.

The holders of Class B Preferred Units have the right at any time to request conversion in whole or in part of their Class B Preferred Units at the Conversion Rate, subject to the requirement to convert a minimum of $17,500,000 of

Class B Preferred Units. The “Conversion Rate” is equal to the quotient of (i) the aggregate purchase price for the Class B Preferred Units plus accrued and unpaid distributions thereon, divided by (ii) the lesser of (a) the purchase price for the Class B Preferred Units and (b) the volume weighted average price for which common units are issued by the Partnership during the period beginning on the private placement closing date and ending on the date on which the Partnership has issued common units (other than issuances pursuant to the LTIP) in exchange for cash in an aggregate amount equal to at least $75 million.

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The Class B Preferred Units are accounted for as mezzanine equity in the consolidated balance sheet consisting of the following (in thousands):

	June 30, 2016	December 31, 2015
Mezzanine equity beginning balance	$ 172,111	$ —
Private placement of Class B Preferred Units	—	350,000
Discount	(87)	(191,901)
Amortization of discount	12,908	6,594
Distributions	17,500	7,418
Distributions paid	(16,168)	—
Total mezzanine equity	$ 186,264	$ 172,111

Earnings per Unit

For the period prior to our conversion, the basic net income per unit was computed from the two-class method by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. To determine net income (loss) allocated to each class of ownership (Class A and Class B), we first allocated net income (loss) in accordance with the amount of distributions made for the period by each class, if any. The remaining net income (loss) was allocated to each class in proportion to the class weighted average number of units outstanding for the period, as compared to the weighted average number of units for all classes for the period.

Post conversion, 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 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 for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income 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 per unit. Undistributed income 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.

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Our general partner does not have an economic interest in the Partnership and, therefore, does not participate in the Partnership's net income. The following table presents the weighted average basic and diluted units outstanding for the periods indicated:

	Three Months Ended		Six Months Ended		
	June 30, 2016	June 30, 2015	June 30, 2016	March 6 - June 30 2015	January 1 - March 6 2015
Class A units - Basic and Diluted	—	—	—	—	48,451
Class B Common units - Basic and Diluted	—	—	—	—	2,879,163
Common units - Basic and Diluted	3,935,297	3,113,428	3,333,482	3,087,431	—
Weighted Common units - Basic and Diluted	3,935,297	3,113,428	3,333,482	3,087,431	2,927,613

At June 30, 2016, we had 328,715 common units that were restricted unvested common units granted and outstanding. No losses were allocated to participating restricted unvested units because such securities do not have a contractual obligation to share in the Partnership's losses.

The following table presents our basic and diluted loss per unit for the six months ended June 30, 2016 (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss to be allocated	$ (27,947)	$ (27,947)
Basic and diluted loss per unit		$ (8.38)

The following table presents our basic and diluted loss per unit for the three months ended June 30, 2016 (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss to be allocated	$ (17,207)	$ (17,207)
Basic and diluted loss per unit		$ (4.37)

The following table presents our basic and diluted loss per unit for the period from January 1, 2015 to March 6, 2015 (the date of conversion to a limited partnership) (in thousands, except for per unit amounts):

	Total	Class A Units	Class B Units
Assumed net loss to be allocated January 1 - March 6	$ (923)	$ (18)	$ (905)
Basic and diluted loss per unit		$ (0.38)	$ (0.31)

The following table presents our basic and diluted loss per unit for the period from March 6, 2015 through June 30, 2015 (the period after conversion to a limited partnership) (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss attributable to common unitholders to be allocated March 6 - June 30	$ (99,928)	$ (99,928)
Basic and diluted loss per unit		$ (3.23)

Net loss per unit increased significantly for the period from March 6, 2015 through June 30, 2015 as compared to the period from January 1, 2015 through March 5, 2015 as it included a non-cash impairment charge of $83.7 million. There was no impairment charge recorded for the period from January 1, 2015 through March 5, 2015.

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15. REPORTABLE SEGMENTS

The operating segments, reported separately herein, are best defined as: (1) Exploration and Production and (2) Midstream. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The Exploration and Production segment operates to explore for and produce crude oil and natural gas. The Midstream segment operates the gathering, processing and transportation of crude oil, natural gas liquids ("NGLs") and natural gas. We completed the Western Catarina Midstream Acquisitions during the fourth quarter of 2015. As such, there were no midstream results for the three and six monthes ended June 30, 2015. 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 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.

The following tables set forth our segment information for the periods indicated (in thousands):

	Three Months Ended June 30, 2016		
	Exploration & Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 600	$ —	$ 600
Oil sales	(2,756)	—	(2,756)
Natural gas liquids sales	244	—	244
Gathering and transportation sales	—	14,258	14,258
Total operating revenues	(1,912)	14,258	12,346
Operating expenses:			
Lease operating expenses	3,904	274	4,178
Transportation operating expenses	—	3,014	3,014
Cost of sales	63	—	63
Production taxes	326	—	326
General and administrative	3,550	1,428	4,978
Unit compensation expense	1,091	—	1,091
Depreciation, depletion and amortization	1,036	5,093	6,129
Asset impairments	—	—	—
Accretion expense	253	62	315

Total operating expenses	10,223	9,871	20,094
Operating income (loss)	$ (12,135)	$ 4,387	$ (7,748)

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	Three Months Ended June 30, 2015		
	Exploration & Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 3,642	$ —	$ 3,642
Oil sales	639	—	639
Natural gas liquids sales	500	—	500
Gathering and transportation sales	—	—	—
Total operating revenues	4,781	—	4,781
Operating expenses:			
Lease operating expenses	5,358	—	5,358
Cost of sales	125	—	125
Production taxes	583	—	583
General and administrative	3,351	—	3,351
Unit compensation expense	395	—	395
Gain on sale of assets	(54)	—	(54)
Depreciation, depletion and amortization	3,079	—	3,079
Asset impairments	862	—	862
Accretion expense	264	—	264
Total operating expenses	13,963	—	13,963
Operating loss	$ (9,182)	$ —	$ (9,182)

	Six Months Ended June 30, 2016		
	Exploration & Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 4,275	$ —	$ 4,275
Oil sales	2,587	—	2,587
Natural gas liquids sales	520	—	520
Gathering and transportation sales	—	28,133	28,133
Total operating revenues	7,382	28,133	35,515
Operating expenses:			
Lease operating expenses	8,780	371	9,151
Transportation operating expenses	—	6,068	6,068
Cost of sales	193	—	193
Production taxes	547	—	547
General and administrative	7,984	2,713	10,697
Unit compensation expense	1,529	—	1,529
Depreciation, depletion and amortization	3,149	10,168	13,317

Asset impairments	1,309	—	1,309
Accretion expense	507	123	630
Total operating expenses	23,998	19,443	43,441
Operating income (loss)	$ (16,616)	$ 8,690	$ (7,926)

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	Six Months Ended June 30, 2015 Exploration & Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 10,216	$ —	$ 10,216
Oil sales	5,603	—	5,603
Natural gas liquids sales	886	—	886
Gathering and transportation sales	—	—	—
Total operating revenues	16,705	—	16,705
Operating expenses:			
Lease operating expenses	10,258	—	10,258
Cost of sales	330	—	330
Production taxes	953	—	953
General and administrative	10,906	—	10,906
Unit compensation expense	2,387	—	2,387
Gain on sale of assets	(113)	—	(113)
Depreciation, depletion and amortization	6,199	—	6,199
Asset impairments	83,727	—	83,727
Accretion expense	517	—	517
Total operating expenses	115,164	—	115,164
Operating loss	$ (98,459)	$ —	$ (98,459)

The following table summarizes the total assets by operating segment as of June 30, 2016 and December 31, 2015 (in thousands):

Segment Assets	June 30, 2016	December 31, 2015
Exploration & Production	$ 59,920	$ 118,083
Midstream	380,137	353,217
Total assets	$ 440,057	$ 471,300

16. SUBSEQUENT EVENTS

On June 15, 2016, certain wholly-owned subsidiaries of the Partnership entered into an agreement with Gateway Resources U.S.A., Inc. to sell substantially all of the Partnerships' operated oil and gas wells, leases and other associated assets and interests in Oklahoma and Kansas (other than those arising under or related to a concession agreement with the Osage Nation) for cash consideration of $7,120, subject to adjustment for title and environmental defects, effective as of August 1, 2016 (the "Effective Time"). In addition, Gateway Resources U.S.A., Inc. agreed to assume all obligations relating to the assets arising after the Effective Time and all plugging and abandonment costs relating to the assets arising prior to the Effective Time. The Partnership closed the sale of this transaction on July 15, 2016. There is no remaining book value of the assets to be sold. Therefore, the Partnership does not expect to record a loss on the transaction.

On July 5, 2016, the Partnership entered into an agreement with SN and SN Midstream, LLC, a wholly-owned subsidiary of SN, to purchase 50% of the issued and outstanding membership interests in Carnero Gathering, LLC for total consideration of approximately $37.0 million, plus the assumption of approximately $7.4 million of remaining capital contribution commitments, of which $1.7 million was paid in July 2016. In addition, the Partnership is required to pay an earnout based on gas received at the delivery points from SN Catarina, LLC, a wholly-owned subsidiary of SN, and other producers. The membership interests acquired

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constitute 50% of the outstanding membership interests in Carnero Gathering, LLC, with the other 50% of the membership interests being owned by TPL SouthTex Processing Company LP. Carnero Gathering, LLC is developing and constructing a gas gathering pipeline from an interconnection in Webb County, Texas to interconnection(s) with a gas processing facility being developed and constructed by Carnero Processing, LLC.

On July 5, 2016, the Partnership and certain of its subsidiaries entered into that certain Fourth Amendment to Third Amended and Restated Credit Agreement dated as of March 31, 2015 among the Partnership, the guarantors party thereto, each of the lenders party thereto, and Royal Bank of Canada, as administrative agent and collateral agent. Pursuant to the Amendment, the following amendments to the Credit Agreement were made: pricing table was increased; certain covenants were amended to permit the Partnership to own equity interests in joint ventures (including Carnero Gathering, LLC); the Midstream Adjusted EBITDA definition was amended to include in the calculation thereof any distributions received in cash from a joint venture so long as such amount does not exceed 20% of the Midstream Adjusted EBITDA and so long as a “Trigger Event” has not occurred. A “Trigger Event” is defined to be: (i) the ownership and control of less than all of the equity interests initially owned in a joint venture, (ii) the incurrence by the joint venture of any debt other than certain permitted debt, (iii) the disposition by the joint venture of a material portion of its assets, (iv) the incurrence by the joint venture of any liens other than certain permitted liens, (v) the modification of any gathering, compressing, processing, transportation, services or other commercial agreement to which the primary revenues of the joint venture are attributable if the effect of such modification is to reduce in any material respect any minimum committed volumes or minimum committed service level thereunder, or (vi) the joint venture voluntarily filing bankruptcy; a new repayment event was added with respect to any cash or cash equivalents held by the Partnership in excess of $10,000,000 (other than cash set aside to pay distributions in the next 90 days); the title requirement with respect to proved reserves was increased from 80% to 90%; the Partnership is required to pledge its equity interests in any joint venture as collateral under the Credit Agreement; the Partnership, and any of its designees to the board of a joint venture, are restricted from voting on any matter set forth in clauses (ii) through (v) of the definition of “Trigger Event” without the consent of the majority lenders; 10% availability on the entire credit facility (rather than just the RBL component) is required before the Partnership can make distributions; and certain technical revisions were made.

On August 10, 2016, the board of directors of the general partner of the Partnership declared cash distributions of $0.4183 per common unit and $0.450 per Class B preferred unit for the second quarter of 2016. The distributions are payable on August 31, 2016 to unitholders of record on August 22, 2016.

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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. Please read "Cautionary Note Regarding Forward-Looking Statements."

Overview

Sanchez Production Partners LP, a Delaware limited partnership (together with our consolidated subsidiaries "SPP", "we", "us", "our" or the "Partnership"), is a publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and other energy production assets. We have entered into a shared services agreement (the "Services Agreement") with the sole member of our general partner (the "Manager") pursuant to which the Manager provides services that the we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals and acquisition, disposition and financing services. Our common units are currently listed on the NYSE MKT under the symbol "SPP."

Historically, our operations have consisted of the exploration and production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("SN") and entered into a 15-year gathering and processing agreement with SN. In July 2016, we sold a significant portion of our oil and gas properties in the Mid-Continent region.

As a result of the acquisition of midstream assets from SN and the disposition of our oil and gas properties located in the Mid-Continent region, our historical financial statements (including those in this Form 10-Q) differ substantially from our past financial statements beginning with the quarter ending December 31, 2015 principally because a significant portion of our revenues will now from the long-term, fee-based gathering and processing agreement with SN rather than from oil and natural gas production.

How We Evaluate our Operations

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

- our throughput volumes on the gathering system upon acquiring those assets;
- our operating expenses; and
- our Adjusted EBITDA.

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Throughput Volumes

Upon acquisition of the Western Catarina gathering system, our management began to analyze our performance based on the aggregate amount of throughput volumes on the Western Catarina gathering system. We must connect additional wells or well pads within the dedicated areas in order to maintain or increase throughput volumes on the Western Catarina gathering system. Our success in connecting additional wells is impacted by successful drilling activity by SN on the acreage dedicated to the Western Catarina gathering system, our ability to secure volumes from SN 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.

Operating Expenses

Our management seeks to maximize Adjusted EBITDA in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (lease operating expenses, labor, vehicle, 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 gas production or the throughput volumes on the gathering system but fluctuate depending on the scale of our operations during a specific period.

Non-GAAP Financial Measures—Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) adjusted by:

- interest (income) expense, net which includes:
- interest expense
- interest expense net (gain) loss on interest rate derivative contracts
- interest (income)
- income tax expense (benefit);
- depreciation, depletion and amortization;
- asset impairments;
- accretion expense;
- (gain) loss on sale of assets;
- (gain) loss from equity investment;
- unit-based compensation programs;
- unit-based asset management fees;
- (gain) loss on mark-to-market activities; and
- (gain) loss on embedded derivatives.

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 flow 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:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- 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 generally accepted accounting principle ("GAAP") measures most directly comparable to Adjusted EBITDA are net income and net cash provided by operating activities. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income and net cash provided by operating

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activities. 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 their utility.

The following table presents a reconciliation of net income (loss) to Adjusted EBITDA, our most directly comparable U.S. GAAP performance measure, for each of the periods presented (in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$ (1,952)	$ (10,341)	$ 3,325	$ (100,327)
Adjusted by:				
Interest expense, net	1,103	1,122	2,002	1,768
Depreciation, depletion and amortization	6,129	3,079	13,317	6,199
Asset impairments	—	862	1,309	83,727
Accretion expense	315	264	630	517
Gain on sale of assets	—	(54)	—	(113)
Unit-based compensation programs	1,091	396	1,529	2,388
Unit-based asset management fees	1,627	—	2,912	—
Loss on mark-to-market activities	13,210	9,902	16,314	10,634
Gain on embedded derivatives	(6,898)	—	(13,192)	—
Adjusted EBITDA	$ 14,625	$ 5,230	$ 28,146	$ 4,793

Significant Operational Factors

- Production. Our production for the six months ended June 30, 2016, was 607 MBOE, or an average of 3,334 BOE per day, compared with approximately 725 MBOE, or an average of 4,007 BOE per day, for the six months ended June 30, 2015.
- Capital Expenditures. For the six months ended June 30, 2016, we spent approximately $2.3 million in capital expenditures, consisting of $1.8 million related to the development of Western Catarina midstream assets and $0.5 related to the development of oil and natural gas properties in the Palmetto Field in Gonzales County, Texas. For the six months ended June 30, 2015, we spent approximately $84.2 million in capital expenditures, consisting of $83.4 million for the purchase of oil and natural gas properties in the Palmetto Field in Gonzales County, Texas (the “Eagle Ford properties” and such acquisition, the “Eagle Ford acquisition”), $0.5 million in development expenditures focused on properties in Texas and Louisiana and $0.3 million in development expenditures focused on oil completions in the Cherokee Basin. These expenditures were funded with cash on hand, borrowings under our credit facility and the issuance of common units as part of our consideration given in the Eagle Ford acquisition.
- Hedging Activities. For the six months ended June 30, 2016, the non-cash mark-to-market loss for our commodity derivatives was approximately $16.3 million, compared to a loss of $10.6 million for the same period in 2015.

Recent Developments

On June 15, 2016, we entered into an agreement with Gateway Resources U.S.A., Inc. to sell substantially all of the Partnerships’ operated oil and gas wells, leases and other associated assets and interests in Oklahoma and Kansas (other than those arising under or related to a concession agreement with the Osage Nation) for cash consideration of $7,120, subject to adjustment for title and environmental defects, effective as of August 1, 2016. The partnership closed the sale of this transaction on July 15, 2016.

On July 5, 2016, the Partnership entered into an agreement with SN and SN Midstream, LLC, a wholly-owned subsidiary of SN, to purchase 50% of the issued and outstanding membership interests in Carnero Gathering, LLC for total consideration of approximately $37.0 million, plus the assumption of approximately $7.4 million of remaining capital contribution commitments, of which $1.7 million was paid in July 2016. In addition, the Partnership is required to pay an earnout based on gas received at the delivery points from SN Catarina, LLC, a wholly-owned subsidiary of SN, and other producers. The membership interests acquired constitute 50% of the outstanding membership interests in Carnero Gathering, LLC, with the other 50% of the membership interests being owned by TPL SouthTex Processing Company LP. Carnero Gathering, LLC is developing and constructing a gas gathering pipeline from an interconnection in Webb County, Texas to interconnection(s) with a gas processing facility being developed and constructed by Carnero Processing, LLC.

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Results of Operations by Segment

Three months ended June 30, 2016 compared to three months ended June 30, 2015

Exploration & Production Operating Results

The following tables sets forth the selected financial and operating data for the periods indicated (dollars in thousands, except for net production and average sales and costs):

	For the Three Months Ended June 30,		Variance	
	2016	2015		
Revenues:				
Natural gas sales at market price	$ 2,398	$ 3,618	$ (1,220)	(34) %
Natural gas hedge settlements	2,287	1,877	410	22 %
Natural gas mark-to-market activities	(3,753)	(2,219)	(1,534)	69 %
Natural gas total	932	3,276	(2,344)	(72) %
Oil sales	3,505	6,194	(2,689)	(43) %
Oil hedge settlements	3,196	2,128	1,068	50 %
Oil mark-to-market activities	(9,457)	(7,683)	(1,774)	23 %
Oil total	(2,756)	639	(3,395)	(531) %
Natural gas liquids sales	244	500	(256)	(51) %
Miscellaneous income	(332)	366	(698)	(191) %
Total revenues	(1,912)	4,781	(6,693)	(140) %
Operating expenses:				
Lease operating expenses	3,904	5,358	(1,454)	(27) %
Cost of sales	63	125	(62)	(50) %
Production taxes	326	583	(257)	(44) %
General and administrative	3,550	3,351	199	6 %
Unit compensation expense	1,091	395	696	176 %
Gain on sale of assets	—	(54)	54	(100) %
Depreciation, depletion and amortization	1,036	3,079	(2,043)	(66) %
Asset impairments	—	862	(862)	(100) %
Accretion expenses	253	264	(11)	(4) %
Total operating expenses	10,223	13,963	(3,740)	(27) %
Operating income (loss):	(12,135)	(9,182)	(2,953)	32 %

(a) Not Meaningful "NM"

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	For the Three Months Ended June 30, 2016	2015	Variance	
Net production:				
Natural gas production (MMcf)	1,209	1,553	(344)	(22)%
Oil production (MBbl)	82	112	(29)	(26)%
Natural gas liquids production (MBbl)	20	31	(10)	(34)%
Total production (MBOE)	304	402	(98)	(24)%
Average daily production (BOE/d)	3,335	4,414	(1,079)	(24)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.88	$ 3.54	$ 0.34	10 %
Natural gas price per Mcf without hedge settlements	$ 1.98	$ 2.33	$ (0.35)	(15)%
Oil price per Bbl with hedge settlements	$ 81.72	$ 74.43	$ 7.28	10 %
Oil price per Bbl without hedge settlements	$ 42.74	$ 55.40	$ (12.65)	(23)%
Liquid price per Bbl without hedge settlements	$ 12.20	$ 16.18	$ (3.98)	(25)%
Total price per BOE with hedge settlements	$ 38.32	$ 35.65	$ 2.67	7 %
Total price per BOE without hedge settlements	$ 20.25	$ 25.68	$ (5.42)	(21)%
Average unit costs per BOE:				
Field operating expenses(a)	$ 13.94	$ 14.79	$ (0.87)	(6) %
Lease operating expenses	$ 12.86	$ 13.34	$ (0.47)	(5) %
Production taxes	$ 1.07	$ 1.45	$ (0.38)	(26)%
General and administrative expenses	$ 15.29	$ 9.33	$ 5.96	64 %
General and administrative expenses without unit-based compensation	$ 11.70	$ 8.34	$ 3.36	40 %
Depreciation, depletion and amortization	$ 3.41	$ 7.67	$ (4.25)	(55)%

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

Production. For the three months ended June 30, 2016, 27% of our production was oil, 6% was NGLs and 67% was natural gas as compared to the three months ended June 30, 2015, where 28% of our production was oil, 8% was NGLs and 64% was natural gas. The production mix between the periods has remained fairly consistent and we expect this product mix to remain relatively consistent for the remainder of 2016.

Oil, NGL and natural gas sales. Unhedged oil sales decreased $2.7 million, or 43%, to $3.5 million for the three months ended June 30, 2016, compared to $6.2 million for the same period in 2015. NGL sales decreased $0.3 million, or 51%, to $0.2 million for the three months ended June 30, 2016, compared to $0.5 million for the same period in 2015. Unhedged natural gas sales decreased $1.2 million, or 34%, to $2.4 million for the three months ended June 30, 2016, compared to $3.6 million for the same period in 2015.

Including hedges and mark-to-market activities, our total revenue decreased $6.7 million for the three months ended June 30, 2016, compared to the same period in 2015. This decrease was the result of a $3.3 million increase in losses on mark-to-market activities, a $2.5 million decrease related to lower sales volumes and a $1.9 million decrease attributable to lower market prices for all products, offset by a $1.5 million increase in settlements on commodity derivatives.

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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 June 30, 2016 to the three months ended June 30, 2015 (dollars in thousands, except average sales price):

	Q2 2016 Production Volume	Q2 2015 Production Volume	Production Volume Difference	Q2 2015 Average Sales Price(a)	Revenue Increase/(Decrease) due to Production
Natural gas (Mcf)	1,209	1,553	(344)	$ 2.33	$ (802)
Oil (MMBbl)	82	112	(30)	$ 55.40	$ (1,651)
Natural gas liquids (MMbl)	20	31	(11)	$ 16.18	$ (176)
Total oil equivalent (Mboe)	304	402	(98)	$ 25.68	$ (2,629)

(a) Average sales prices presented represent on a per BOE basis.

	Q2 2016 Average Sales Price(a)	Q2 2015 Average Sales Price(a)	Average Sales Price Difference	Q2 2016 Volume	Revenue Decrease due to Price
Natural gas (Mcf)	$ 1.98	$ 2.33	$ (0.35)	1,209	$ (418)
Oil (MMBbl)	$ 42.74	$ 55.40	$ (12.66)	82	$ (1,038)
Natural gas liquids (MMbl)	$ 12.20	$ 16.18	$ (3.98)	20	$ (80)
Total oil equivalent (Mboe)	$ 20.25	$ 25.68	$ (5.42)	304	$ (1,536)

(a) Average sales prices presented represent on a per BOE basis.

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 June 30, 2016 by $0.6 million.

Hedging activities. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and gas revenues. For the three months ended June 30, 2016, the non-cash mark-to-market loss was $13.2 million, compared to a loss of $9.9 million for the same period in 2015. The 2016 and 2015 non-cash losses were the result of the impact of higher future expected oil and natural gas prices on these derivative transactions. Cash settlements, including settlements receivable, for our commodity derivatives were $5.5 million for the three months ended June 30, 2016, compared to $4.0 million for the three months ended June 30, 2015.

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 decreased $1.4 million, or 27%, to $4.0 million for the three months ended June 30, 2016, compared to $5.4 million during the same period in 2015. On a per unit basis, lease operating expenses were $12.86 per BOE, for the three months ended June 30, 2016, and $13.34 per BOE as compared to the same period in 2015. The decreased lease operating expenses per BOE for the comparative periods were primarily the result of workovers performed in our Woodford Shale properties during the second quarter of 2015.

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 the Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit compensation expense, increased $0.9 million, or 24%, to $4.6 million for the three months ended June 30, 2016, compared to $3.8 million for the same period in 2015. Our general and administrative expenses were higher in 2016 primarily due to a $0.7 million increase in executive unit compensation expense during the three months ended June 30, 2016 as compared to the same period in 2015.

Our general and administrative expenses were $15.29 per BOE for the three months ended June 30, 2016, compared to $9.33 per BOE for the same period in 2015. Excluding unit-based compensation, our general and administrative costs were $11.70 per BOE for the three months ended June 30, 2016, compared to $8.34 per BOE for the same period in 2015. This increase resulted from the increased costs noted above.

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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, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the three months ended June 30, 2016 was $1.0 million, or $3.41 per BOE, compared to $3.1 million, or $7.67 per BOE, for the same period in 2015. This decrease is the result of lower property values due to non-cash impairment charges previously recorded as well as increases to total proved reserves between the periods impacting the depletion rate. The overall expense decrease, combined with the decreased production between periods, resulted in the decrease in the per BOE expense. Our non-oil and gas properties are depreciated using the straight-line basis.

Impairment expense. For the three months ended June 30, 2016, no impairment was recorded. During the same period in 2015, our non-cash impairment charges were $0.9 million related to our oil and natural gas fields located in the Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties. The impairment expense recorded during the three months ended June 30, 2016 resulted from decreases in expectations for oil and natural gas prices in the future as well as changes to our expected future production estimates in certain areas.

Interest expense. Interest expense for the three months ended June 30, 2016 decreased by a de minimis amount to $1.1 million, compared to $1.1 million for the same period in 2015.

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):

	For the Three Months Ended June 30,		Variance	
	2016	2015		
Revenues:				
Gathering and transportation sales	$ 14,258	$ —	$ 14,258	NM (a)
Total gathering and transportation sales	14,258	—	14,258	NM (a)
Operating expenses:				
Lease operating expenses	274	—	274	NM (a)
Gathering and transportation operating expenses	3,014	—	3,014	NM (a)
General and administrative	1,428	—	1,428	NM (a)
Depreciation, amortization and accretion expense	5,093	—	5,093	NM (a)
Accretion expenses	62	—	62	NM (a)
Total operating expenses	9,871	—	9,871	NM (a)
Operating income (loss):	4,387	—	4,387	NM (a)

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

Items Affecting the Comparability of Our Financial Results. Historical results of operations for the periods presented for the Midstream segment are deemed to be not meaningful as this segment was acquired and placed into service in October 2015. As a result, year-over-year variances are not applicable as any revenues or expenses generated from the gathering and transportation of hydrocarbons relate exclusively to the current quarter. See Note 3. "Acquisitions" for additional information relating to the Western Catarina Midstream acquisition.

Gathering and transportation sales. We consummated the acquisition of the Western Catarina gathering system from SN and entered into the Western Catarina gathering and processing agreement with SN in October 2015. During the three months ended June 30, 2016, SN transported average daily production through the gathering system of approximately 1,414 MBbls/d of crude oil and 19,325 MMcf/d of natural gas.

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 integrity management expenses. Our transportation operating expense for the three months ended June 30, 2016 was $3.0 million.

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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 the Manager in connection with the Services Agreement and other costs not directly associated with field operations. Our general and administrative expenses totaled $1.4 million for the three months ended June 30, 2016.

Depreciation, amortization and accretion 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 12 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation, amortization and accretion expense for the three months ended June 30, 2016 was $5.1 million.

Six months ended June 30, 2016 compared to six months ended June 30, 2015

Exploration & Production Operating Results

The following tables sets forth the selected financial and operating data for the periods indicated (dollars in thousands, except net production and average sales and costs):

	For the Six Months Ended June 30,		Variance	
	2016	2015		
Revenues:				
Natural gas sales at market price	$ 4,508	$ 6,837	$ (2,329)	(34) %
Natural gas hedge settlements	4,526	3,418	1,108	32 %
Natural gas mark-to-market activities	(4,694)	(1,570)	(3,124)	199 %
Natural gas total	4,340	8,685	(4,345)	(50) %
Oil sales	6,155	8,515	(2,360)	(28) %
Oil hedge settlements	8,052	6,152	1,900	31 %
Oil mark-to-market activities	(11,620)	(9,064)	(2,556)	28 %
Oil total	2,587	5,603	(3,016)	(54) %
Natural gas liquid sales	520	886	(366)	(41) %
Miscellaneous income	(65)	1,531	(1,596)	(104)%
Total revenues	7,382	16,705	(9,323)	(56) %
Operating expenses:				
Lease operating expenses	8,780	10,258	(1,478)	(14) %
Cost of sales	193	330	(137)	(42) %
Production taxes	547	953	(406)	(43) %
General and administrative	7,984	10,906	(2,922)	(27) %
Unit compensation expense	1,529	2,387	(858)	(36) %
Gain on sale of assets	—	(113)	113	NM (a)
Depreciation, depletion and amortization	3,149	6,199	(3,050)	(49) %
Asset impairments	1,309	83,727	(82,418)	(98) %
Accretion expenses	507	517	(10)	(2) %
Total operating expenses	23,998	115,164	(91,166)	(79) %
Operating income (loss):	(16,616)	(98,459)	81,843	(83) %

(a) Not Meaningful “NM.”

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	For the Six Months Ended June 30, 2016	2015	Variance	
Net production:				
Natural gas production (Mcf)	2,381	3,124	(743)	(24)%
Oil production (MBbl)	168	156	12	8 %
Natural gas liquids production (MBbl)	42	48	(6)	(12)%
Total production (MBOE)	607	725	(118)	(16)%
Average daily production (BOE/d)	3,334	4,007	(673)	(17)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.79	$ 3.28	$ 0.52	16 %
Natural gas price per Mcf without hedge settlements	$ 1.89	$ 2.19	$ (0.29)	(13)%
Oil price per Bbl with hedge settlements	$ 84.57	$ 93.94	$ (9.37)	(10)%
Oil price per Bbl without hedge settlements	$ 36.64	$ 54.54	$ (17.90)	(33)%
Liquid price per Bbl without hedge settlements	$ 12.38	$ 18.31	$ (5.94)	(32)%
Total price per BOE with hedge settlements	$ 39.16	$ 35.59	$ 3.57	10 %
Total price per BOE without hedge settlements	$ 18.43	$ 22.39	$ (3.96)	(18)%
Average unit costs per BOE:				
Field operating expenses (a)	$ 15.37	$ 15.46	$ (0.09)	(1) %
Lease operating expenses	$ 14.47	$ 14.14	$ 0.32	2 %
Production taxes	$ 0.90	$ 1.31	$ (0.41)	(31)%
General and administrative expenses	$ 15.68	$ 15.04	$ 0.64	4 %
General and administrative expenses without unit-based compensation	$ 13.16	$ 11.75	$ 1.41	12 %
Depreciation, depletion and amortization	$ 5.19	$ 8.55	$ (3.36)	(39)%

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

Production. For the six months ended June 30, 2016, 28% of our production was oil, 7% was NGLs and 65% was natural gas as compared to the six months ended June 30, 2015, where 22% of our production was oil, 7% was NGLs and 71% was natural gas. The amount of oil as a percentage of total production has increased during the six months ended June 30, 2016 due to the addition of production from the Eagle Ford properties acquired on March 31, 2015, which are significantly more weighted towards oil than our previous asset base. We expect this product mix to remain relatively consistent for the remainder of 2016.

Oil, NGL and natural gas sales. Unhedged oil sales decreased $2.4 million, or 28%, to $6.2 million for the six months ended June 30, 2016, compared to $8.5 million for the same period in 2015. NGL sales decreased $0.4 million, or 41%, to $0.5 million for the six months ended June 30, 2016, compared to $0.9 million for the same period in 2015. Unhedged natural gas sales decreased $2.3 million, or 34%, to $4.5 million for the six months ended June 30, 2016, compared to $6.8 million for the same period in 2015.

Including hedges and mark-to-market activities, our total revenue decreased $9.3 million for the six months ended June 30, 2016, compared to the same period in 2015. This decrease was the result of a $5.7 million increase in losses on mark-to-market activities, a $4.0 million decrease attributable to lower market prices for all products and a $1.1 million decrease related to lower sales volumes, offset by a $3.0 million increase in settlements on commodity derivatives.

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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 six months ended June 30, 2016 compared to the six months ended June 30, 2015 (dollars in thousands, except average sales price):

	YTD 2016 Production Volume	2015 Production Volume	Production Volume Difference	2015 Average Sales Price(a)	Revenue Increase/(Decrease) due to Production
Natural gas (Mcf)	2,381	3,124	(743)	$ 2.19	$ (1,627)
Oil (MBbl)	168	156	12	$ 54.54	$ 647
Natural gas liquids (Mbl)	42	48	(6)	$ 18.31	$ (117)
Total oil equivalent (Mboe)	607	725	(118)	$ 22.39	$ (1,097)

(a) Average sales prices presented represent on a per BOE basis.

	2016 Average Sales Price(a)	2015 Average Sales Price(a)	Average Sales Price Difference	2016 Volume	Revenue Decrease due to Price
Natural gas (Mcf)	$ 1.89	$ 2.19	$ (0.29)	2,381	$ (702)
Oil (MBbl)	$ 36.64	$ 54.54	$ (17.90)	168	$ (3,007)
Natural gas liquids (Mbl)	$ 12.38	$ 18.31	$ (5.94)	42	$ (249)
Total oil equivalent (Mboe)	$ 18.43	$ 22.39	$ (3.96)	607	$ (3,958)

(a) Average sales prices presented represent on a per BOE basis.

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 six months ended June 30, 2016 by $1.1 million.

Hedging activities. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and gas revenues. For the six months ended June 30, 2016, the non-cash mark-to-market loss was $16.3 million, compared to a loss of $10.6 million for the same period in 2015. The 2016 and 2015 non-cash losses were the result of the impact of higher future expected oil and natural gas prices on these derivative transactions. Cash settlements, including settlements receivable, for our commodity derivatives were $12.6 million for the six months ended June 30, 2016, compared to $9.6 million for the six months ended June 30, 2015.

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 decreased $1.5 million, or 14%, to $8.8 million for the six months ended June 30, 2016, compared to $10.3 million during the same period in 2015. On a per unit basis, lease operating expenses were $14.47 per BOE, for the six months ended June 30, 2016, and $14.14 per BOE as compared to the same period in 2015. The increased lease operating expenses per BOE for the comparative periods were primarily the result of a full six months of ownership in 2016 of our oil and gas properties in the Eagle Ford, which we acquired on March 31, 2015.

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 the Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit compensation expense, decreased $3.8 million, or 29%, to $9.5 million for the six months ended June 30, 2016, compared to $13.3 million for the same period in 2015. Our general and administrative expenses were lower in 2016 due to a $3.9 million decrease in executive termination costs.

Our general and administrative expenses were $15.68 per BOE for the six months ended June 30, 2016, compared to $15.04 per BOE for the same period in 2015. Excluding unit-based compensation, our general and administrative costs were $13.16 per BOE for the six months ended June 30, 2016, compared to $11.75 per BOE for the same period in 2015. This decrease resulted from the decreased costs noted above.

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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, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2016 was $3.2 million, or $5.19 per BOE, compared to $6.2 million, or $8.55 per BOE, for the same period in 2015. This overall decrease is the result of lower property values due to non-cash impairment charges previously recorded as well as increases to total proved reserves between the periods impacting the depletion rate. The overall expense decrease, combined with the decreased production between periods, resulted in the decrease in the per BOE expense. Our non-oil and gas properties are depreciated using the straight-line basis.

Impairment expense. For the six months ended June 30, 2016, we recorded non-cash charges of $1.3 million to impair the value of our oil and natural gas fields located in Texas and Louisiana. During the same period in 2015, our non-cash impairment charges were $83.7 million related to our Cherokee Basin properties, Woodford Shale properties and our Texas and Louisiana properties acquired prior to the Eagle Ford acquisition. The impairment expense recorded during the six months ended June 30, 2016 resulted from decreases in expectations for oil and natural gas prices in the future as well as changes to our expected future production estimates in certain areas.

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):

	For the Six Months Ended June 30, 2016	2015	Variance	
Revenues:				
Gathering and transportation sales	$ 28,133	$ —	$ 28,133	NM (a)
Total gathering and transportation sales	28,133	—	28,133	NM (a)
Operating expenses:				
Lease operating expenses	371	—	371	NM (a)
Gathering and transportation operating expenses	6,068	—	6,068	NM (a)
General and administrative	2,713	—	2,713	NM (a)
Depreciation, amortization and accretion expense	10,168	—	10,168	NM (a)
Accretion expenses	123	—	123	NM (a)
Total operating expenses	19,443	—	19,443	NM (a)
Operating income (loss):	8,690	—	38,515	NM (a)

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

Items Affecting the Comparability of Our Financial Results. Historical results of operations for the periods presented for the Midstream segment are deemed to be not meaningful as this segment was acquired and placed into service in

October 2015. As a result, year-over-year variances are not applicable as any revenues or expenses generated from the gathering and transportation of hydrocarbons relate exclusively to the current quarter. See Note 3. “Acquisitions” for additional information relating to the Western Catarina Midstream acquisition.

Gathering and transportation sales. We consummated the acquisition of the Western Catarina gathering system from SN, and we entered into the Western Catarina gathering and processing agreement with SN, in October 2015. During the six months ended June 30, 2016, SN transported average daily production through the gathering system of approximately 2,804 MBbls/d of crude oil and 38,080 MMcf/d of natural gas.

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 integrity management expenses. Our transportation operating expense for the six months ended June 30, 2016 was $6.1 million.

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 the Manager in connection with the Services Agreement and

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other costs not directly associated with field operations. Our general and administrative expenses for the six months ended June 30, 2016 was $2.7 million.

Depreciation, amortization and accretion 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 12 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation, amortization and accretion expense for the six months ended June 30, 2016 was $10.2 million.

Liquidity and Capital Resources

As of June 30, 2016, we had approximately $1.2 million in cash and cash equivalents and $86.7 million available under the $195.7 million borrowing base of our credit facility in effect on such date. During the three months ended June 30, 2016, we paid approximately $0.8 million in cash for interest on borrowings under our credit facility and approximately $0.1 million in cash for the commitment fee on undrawn commitments. During the six months ended June 30, 2016, we paid approximately $1.5 million in cash for interest on borrowings under our credit facility and approximately $0.2 million in cash for the commitment fee on undrawn commitments.

Our capital expenditures during the six months ended June 30, 2016 were funded with cash on hand and borrowings under our credit facility. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our credit facility 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 intend to distribute at least the quarterly distribution of $0.50 per unit ($2.00 per unit on an annualized basis) on all of our common units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses. 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 facility 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.

On June 15, 2016, we entered into an agreement with Gateway Resources U.S.A., Inc. to sell substantially all of the Partnerships' operated oil and gas wells, leases and other associated assets and interests in Oklahoma and Kansas (other than those arising under or related to a concession agreement with the Osage Nation) for cash consideration of $7,120, subject to adjustment for title and environmental defects, effective as of August 1, 2016. The Partnership closed this transaction on July 15, 2016. As a result of this sale, we anticipate minimal drilling activities in the Mid-Continent region during 2016, which will reduce our capital expenditures and result in a continued decline of our production during the remainder of the year.

Credit Facility

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 facility provides a maximum commitment of $500,000,000 and has a maturity date of March 31, 2020.   Borrowings under the credit facility 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 and certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the credit facility is limited to the borrowing base for our oil and natural gas properties and our midstream assets. Borrowings under the credit facility are available for direct investment in oil and gas properties, acquisitions, and working capital and general business purposes. The credit facility has a sub-limit of $15,000,000, which may be used for the issuance of letters of credit. The initial borrowing base under the credit facility was $200,000,000. 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 equal to the rolling four quarter EBITDA of our midstream operations multiplied by 4.75 for the second quarter of 2016 and 4.5 thereafter. 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.

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Prior to July 5, 2016, interest for borrowings under the credit facility were determined by reference to (i) the London interbank rate ("LIBOR") plus an applicable margin between 1.75% and 2.75% per annum based on utilization or (ii) a domestic bank rate ("ABR") plus an applicable margin between 0.75% and 1.75% per annum based on utilization plus (iii) a commitment fee between 0.375% and 0.500% per annum based on the unutilized borrowing base.

From and after July 5, 2016, interest for borrowings under the credit facility 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 facility 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 facility 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 facility and exercise other rights and remedies.

The credit facility 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 facility, 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 facility 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 June 30, 2016, we were in compliance with the financial covenants contained in the credit facility. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our credit facility 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 facility, such that our outstanding debt 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.

On July 5, 2016, we entered into an amendment to our credit facility. For further information on this amendment please see Part 1. Item 1. Note 16. “Subsequent Events.”

Sources of Debt and Equity Financing

As of June 30, 2016, the borrowing base under our credit facility was set at $195.7 million and we had $109 million of debt outstanding under the facility, leaving us with $86.7 million in unused borrowing capacity. Our credit facility matures on March 31, 2020.

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In May 2015, we executed an at-the-market facility that allows us to sell up to $18.6 million of common units, with any proceeds from such sales to be used for general limited partnership purposes. For the six months ended June 30, 2016, there were no at-the market-sales of common units.

Open Commodity Hedge Position

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.

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 facility 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 June 30, 2016, summarize, for the periods indicated, our hedges currently in place through December 31, 2019. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps—NYMEX (Henry Hub)

	For the Quarter Ended June 30, 2016 (volume in Mcfs)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price
2016					998,394	$ 4.14	963,327	$ 4.14	1,961,721	$ 4.14
2017	80,563	$ 3.52	75,829	$ 3.52	71,672	$ 3.52	67,984	$ 3.52	296,048	$ 3.52
2018	79,042	$ 3.58	75,404	$ 3.58	72,115	$ 3.58	69,122	$ 3.58	295,683	$ 3.58
2019	73,432	$ 3.62	70,648	$ 3.62	68,088	$ 3.62	65,720	$ 3.62	277,888	$ 3.62
									2,831,340	

MTM Fixed Price Basis Swaps–West Texas Intermediate (WTI)

	For the Quarter Ended June 30, 2016 (volume in Bbls)									
	March 31,		June 30,		September 30,		December 31,		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Average Price	Volume	Averag Price
2016					106,483	$ 73.95	100,525	$ 74.10	207,008	$ 74.0

2017	57,953	$ 64.80	54,554	$ 64.80	51,570	$ 64.80	48,926	$ 64.80	213,003	$ 64.8
2018	56,798	$ 65.40	54,197	$ 65.40	51,851	$ 65.40	49,709	$ 65.40	212,555	$ 65.4
2019	52,760	$ 65.65	50,784	$ 65.65	48,960	$ 65.65	47,264	$ 65.65	199,768	$ 65.6
									832,334	

Net Cash Provided by Operations

We had net cash flows provided by operating activities for the six months ended June 30, 2016 of $17.3 million, compared to net cash flow provided by operating activities of $4.9 million for the same period in 2015. This increase was primarily related to the midstream segment which contributed $11.4 million toward net income. Cash flows provided by operations were also benefitted by a $4.1 million increase in settlements on commodity derivatives. These increase in cash flows provided by operations was mitigated by a decrease in accrued liabilities of $5.9 million and an increase in prepaid expenses of $1.8 million, both relating to the midstream segment.

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One of the primary sources of variability in our cash flows from operating activities is fluctuations in commodity prices, the impact of which we mitigate by entering into commodity derivatives. Sales volumes also impact cash flow. Our cash flows from operating activities are also dependent on the costs related to continued operations and debt service. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program, acquisitions and successful execution of our hedging program.

Net Cash Used in Investing Activities

We had net cash flows used in investing activities for the six months ended June 30, 2016 of $2.3 million, consisting of $1.8 million related to the development of Western Catarina midstream assets, and $0.5 million related to the development of oil and natural gas properties in the Palmetto Field in Gonzales County.

During the six months ended June 30, 2015, we had net cash flows used in investing activities of $82.1 million, which included $81.4 million provided as cash consideration paid in the Eagle Ford acquisition, as well as $0.3 million in development expenditures focused on oil completions in the Cherokee Basin and $0.7 million in development expenditures focused on properties in Texas and Louisiana, offset by $0.3 million in proceeds from the sale of assets during the period.

Net Cash Provided by (Used in) Financing Activities

Net cash flows used in financing activities was $20.4 million for the six months ended June 30, 2016. During the six months ended June 30, 2016, we had borrowings under our credit facility of $2.0 million. We distributed $16.2 million and $3.0 million to Class B preferred unit holders and common unit holders respectively during the same period. As part of our unit repurchase program, we used $2.9 million to repurchase and cancel 242,500 common units. Additionally, we paid $0.1 million in offering costs and $0.1 million related to units tendered by employees for tax withholding.

Net cash flows provided by financing activities was $78.2 million for the six months ended June 30, 2015. During the six months ended June 30, 2015, we had borrowings under our credit facility of $106.0 million, $42.5 million of which was paid to satisfy amounts due under our prior credit facility, which was refinanced on March 31, 2015. We received $17.4 million from the private placement of Class A Preferred Units during the period. We also incurred $1.3 million in debt issuance costs associated with the modification of our Credit Agreement on March 31, 2015. We used $0.6 million to fund the cost of units tendered by employees for tax withholdings related to the vesting of units during the period.

Off-Balance Sheet Arrangements

As of June 30, 2016, 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 sale of oil and natural gas and our use of derivatives. Through June 30, 2016, 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 consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions. The results of these estimates and assumptions form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements.

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As of June 30, 2016, 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, 2015, which was filed with the SEC on March 30, 2016. 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 consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

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 not required to provide this disclosure as a smaller reporting company.

Item 4. Controls and Procedures

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with SPP have been detected. These inherent limitations include error by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

The Principal Executive Officer and the Principal Financial Officer of the general partner of SPP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of June 30, 2016 (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

During the three months ended June 30, 2016, there were no changes in SPP’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, SPP’s internal control over financial reporting.

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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

Consider carefully the risk factors under the caption "Risk Factors" under Part I, Item 1A in our 2015 Annual Report on Form 10-K, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2015 Annual Report; and in our other public filings, press releases, and public discussions with our management. Additional risks and uncertainties not currently known to us or that we currently deem immaterial may materially adversely affect our business, financial condition or results of operations.

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

In connection with providing services under the Services Agreement for the fourth quarter of 2015, the Partnership issued 58,363 common units to SP Holdings, LLC on April 1, 2016. See Note 11, "Related Party Transactions" for additional information related to the Services Agreement (in thousands, except unit amounts). The issuance of these common units was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to section 4(2) thereof as a transaction by an issuer not involving a public offering.

The following table provides information relating to the purchase of our common units in the second quarter of 2016.

Period	Total Number of Common Units Purchased	Average Price Paid	Total Number of Common Units Purchased as Part of Publicly Announced Plan(1)	Approximate Dollar Value of Common Units that may yet be Purchased under the Plan(1)
April 1, 2016 - April 30, 2016	4,300	$ 12.00	4,300	$ 4,829
May 1, 2016 - May 31, 2016	-	-	-	4,829
June 1, 2016 - June 30, 2016	-	-	-	4,829

Total	4,300	$ 12.00	4,300	$ 4,829

(1) On November 10, 2015, the board of directors of our general partner approved a $10 million common unit repurchase plan (the "Unit Repurchase Plan"). Under the new Unit Repurchase Plan, we may repurchase up to $10 million of our common units. We may repurchase our common units from time to time, in amounts and at prices that we deem appropriate, subject to market conditions and other considerations. Our repurchase may be executed using open market purchases, privately negotiated agreements or other transactions. The repurchases will be funded from cash on hand or available borrowings. The Unit Repurchase Plan may be suspended or discontinued at any time without prior notice.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

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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 accompanying this form 10-Q and are incorporated herein by reference.

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SIGNATURES

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

SANCHEZ PRODUCTION PARTNERS LP

(REGISTRANT)

BY: Sanchez Production Partners GP LLC, its general partner

Date: August 12, 2016 By /s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer, Treasurer and Secretary

(Duly Authorized Officer and Principal Financial Officer)

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EXHIBIT INDEX

Exhibit Number	Description
10.1* , ***	Purchase and Sale Agreement between certain wholly-owned subsidiaries of Sanchez Production Partners LP and Gateway Resources U.S.A., Inc., dated June 15, 2016, as amended, by that certain Amendment No. 1 to Purchase and Sale Agreement, dated June 15, 2016.
10.2* , ***	Purchase and Sale Agreement by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP, dated July 5, 2016.
10.3*	Fourth Amendment to Third Amended and Restated Credit Agreement among Sanchez Production Partners LP, the guarantors party thereto, each of the lenders party thereto, and Royal Bank of Canada, as administrative agent and collateral agent, dated July 5, 2016.
31.1*	Certification of Principal Executive Officer of Sanchez Production Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer of Sanchez Production Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer of Sanchez Production 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 Production 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

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* Filed herewith.

**Furnished herewith.

***The exhibits and schedules to these agreements have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such omitted exhibits and schedules to the Securities and Exchange Commission upon request. Descriptions of such exhibits and schedules, as applicable, are set forth on page iii of each agreement.