Quarterly Report to Holders of 5.625% Senior Notes due 2025
For the quarterly period ended September 30, 2018

CrownRock, L.P.

18 Desta Drive
Midland, Texas 79705
(432) 818-0300

TABLE OF CONTENTS

Page

FINANCIAL INFORMATION

OTHER INFORMATION

Cautionary Statement Regarding Forward-Looking Statements

Certain statements and information in this report may constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). Such statements and information include projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "should," "would," "could," "may," "foresee," "plan," "goal" and "intend" and other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based forward-looking statements in this report on our current expectations and beliefs about future developments and their potential effect on us. While our management considers forward-looking statements contained in this report to be reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. Forward-looking statements contained in this report are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and present expectations or projections. Known material factors that could cause our actual results to differ from those implied by or expressed in forward-looking statements contained in this report are discussed in "Item 1A. Risk Factors," which include, but are not limited to:

- declines in the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling and operating risks, including risks related to properties where we do not serve as the operator;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of West Texas;
- potential financial losses or earnings reductions resulting from our commodity price risk management program;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- risks and liabilities associated with acquired properties, including the assets acquired in connection with each of our recent acquisitions and property exchanges;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- competition in the oil and natural gas industry; and
- our substantial existing indebtedness.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We disclaim any obligation to update or revise any forward-looking statements contained in this report unless required by securities law.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2018	December 31, 2017
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 123,172	$ 96,067
Accounts receivable – related party:		
Oil and natural gas	67,289	42,682
Other	9,789	769
Prepaid costs and other current assets	1,382	4,928
Derivative instruments	-	59,044
Total current assets	201,632	203,490
Oil and natural gas properties, net, successful efforts method of accounting	2,066,421	1,655,176
Other property and equipment, net	94,991	93,409
Deferred loan costs, net	1,786	2,519
Other assets	8,738	6,267
Total Assets	$ 2,373,568	$ 1,960,861
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable – related party	$ -	$ 97
Accrued drilling cost – related party	29,883	968
Other accrued liabilities – related party	11,525	6,060
Accrued interest payable	30,736	12,500
Current portion of long-term debt	1,030	993
Other current liabilities	572	765
Asset retirement obligations, current portion	262	159
Derivative instruments	44,255	-
Total current liabilities	118,263	21,542
Long-term debt, net	1,176,848	997,005
Noncurrent derivative instruments	22,290	1,241
Asset retirement obligations	22,300	20,072
Other noncurrent liabilities	-	555
Total liabilities	1,339,701	1,040,415
Commitments and Contingencies (Note J)		
CrownRock, L.P. Partners' Capital	1,033,500	919,991
Non-controlling interest in subsidiary	367	455
Total Partners' Capital	1,033,867	920,446
Total Liabilities and Partners' Capital	$ 2,373,568	$ 1,960,861

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)		(In thousands)	
Statements of Income				
Revenues and gains:				
Oil and natural gas sales	$ 198,611	$ 77,491	$ 478,469	$ 223,068
Gain on sales and exchanges of oil and natural gas properties	-	-	63,253	5,409
Rent - gathering system	895	489	1,936	1,322
Transportation fees and saltwater disposal	4,185	908	11,154	2,355
Surface ownership	450	316	1,443	355
Fresh water supply	1,425	-	4,139	-
Total revenues and gains	205,566	79,204	560,394	232,509
Costs and expenses:				
Lease operating expense	26,851	19,048	69,815	48,545
Production and ad valorem taxes	11,679	5,423	27,529	15,714
Exploration costs	1,598	2,625	3,858	10,210
Depreciation, depletion and amortization	65,418	35,668	158,097	102,366
Impairment of oil and natural gas properties and facilities	769	836	2,160	4,528
Accretion of discount on asset retirement obligation	249	212	717	617
General and administrative	6,001	4,765	18,006	15,006
Total costs and expenses	112,565	68,577	280,182	196,986
Operating income	93,001	10,627	280,212	35,523
Other income (expense):				
Gain (loss) on derivatives not designated as hedges	(96,761)	(14,441)	(102,958)	39,801
Loss on extinguishment of debt	-	(47)	-	(47)
Interest income	493	-	666	-
Interest expense	(18,282)	(15,752)	(50,787)	(47,045)
Other income (expense), net	435	(224)	681	(298)
Total other income (expense)	(114,115)	(30,464)	(152,398)	(7,589)
Net income (loss)	(21,114)	(19,837)	127,814	27,934
Net loss attributable to non-controlling interest	30	29	88	82
Net income (loss) attributable to CrownRock, L.P.	$ (21,084)	$ (19,808)	$ 127,902	$ 28,016
Statements of Comprehensive Income (Loss)				
Net income (loss)	$ (21,114)	$ (19,837)	$ 127,814	$ 27,934
Less: Comprehensive loss attributable to the non-controlling interest	30	29	88	82
Comprehensive income (loss) attributable to CrownRock, L.P.	$ (21,084)	$ (19,808)	$ 127,902	$ 28,016

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(Unaudited)

	Limited Partner		Class A		Class B		Class C		Class D		Class E		Treasury Units		Total CrownRock, LP Partners'	Non-Controlling	Total Partners'
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Capital	Interest	Capital
(In thousands, except units)																	
Balance, January 1, 2017	-	$ -	8,848,300	$ 657,578	1,500,000	$ 109,207	1,500,000	$ 196,653	490,500	$ 12,218	-	$ -	79,837	$ (13,538)	$ 962,118	$ 566	$ 962,684
Net loss	-	-	-	(29,395)	-	(4,983)	-	(8,594)	-	-	-	-	-	-	(42,972)	(111)	(43,083)
Distributions to partners	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit-based compensation	-	-	-	-	-	-	-	-	6,000	3,879	5,500	43	-	-	3,922	-	3,922
Purchase of treasury units:																	
Class A units	-	-	-	-	-	-	-	-	-	-	-	-	1,004	(249)	(249)	-	(249)
Class B units	-	-	-	-	-	-	-	-	-	-	-	-	1,110	(275)	(275)	-	(275)
Class C units	-	-	-	-	-	-	-	-	-	-	-	-	1,110	(475)	(475)	-	(475)
Class D units	-	-	-	-	-	-	-	-	-	-	-	-	3,612	(2,078)	(2,078)	-	(2,078)
Class D and E unit forfeitures	-	-	-	-	-	-	-	-	(6,100)	-	(500)	-	-	-	-	-	-
Balance, December 31, 2017	-	$ -	8,848,300	$ 628,183	1,500,000	$ 104,224	1,500,000	$ 188,059	490,400	$ 16,097	5,000	$ 43	86,673	$ (16,615)	$ 919,991	$ 455	$ 920,446
Units canceled upon merger transaction	-	-	(8,848,300)	(628,183)	(1,500,000)	(104,224)	(1,500,000)	(188,059)	(490,400)	(16,097)	(5,000)	(43)	(86,673)	16,615	(919,991)	-	(919,991)
Units issued to CrownRock Holdings upon merger transactions	100	919,991	-	-	-	-	-	-	-	-	-	-	-	-	919,991	-	919,991
Net income (loss)	-	127,902	-	-	-	-	-	-	-	-	-	-	-	-	127,902	(88)	127,814
Distribution to limited partner	-	(17,857)	-	-	-	-	-	-	-	-	-	-	-	-	(17,857)	-	(17,857)
Capital contribution - unit based compensation	-	3,452	-	-	-	-	-	-	-	-	-	-	-	-	3,452	-	3,452
Voided treasury unit purchase																	
Class D units	-	12	-	-	-	-	-	-	-	-	-	-	-	-	12	-	12
Balance, September 30, 2018	100	$1,033,500	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	$ 1,033,500	$ 367	$ 1,033,867

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 127,814	$ 27,934
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	158,097	102,366
Accretion of discount on asset retirement obligation	717	617
Accretion of discount on long-term debt	126	410
Amortization of deferred loan costs	2,169	2,538
Unit-based compensation expense	3,452	3,069
Exploration costs	3,858	10,210
Settlements of asset retirement obligations	(59)	(637)
Impairment of oil and natural gas properties and facilities	2,160	4,528
Loss on derivative instruments	124,348	52,076
Gain on sales and exchanges of oil and natural gas properties	(63,253)	(5,409)
(Income) loss on equity method investments	(688)	43
Change in assets and liabilities:		
Accounts receivable – related party	(33,627)	(3,307)
Prepaid costs and other current assets	3,546	815
Accounts payable - related party	(97)	160
Other accrued liabilities - related party	(885)	(206)
Accrued interest payable	18,236	539
Other liabilities	(735)	(712)
Net cash flows provided by operating activities	345,179	195,034
Cash flows from investing activities:		
Acquisition of leasehold and oil and natural gas properties	(11,091)	(9,850)
Capital expenditures on oil and natural gas properties	(467,886)	(281,033)
Additions to other property and equipment	(4,137)	(32,867)
Proceeds from sales and exchanges of oil and natural gas properties	-	7,332
Contributions to equity method investments	(1,782)	(2,060)
Net cash flows used in investing activities	(484,896)	(318,478)
Cash flows from financing activities:		
Distributions to partners	(11,297)	-
Proceeds from issuance of 5.625% Senior Notes due 2025	181,781	-
Repayments of long-term borrowings under construction loan	(740)	(705)
Proceeds from long-term borrowings under credit facility	55,000	60,000
Repayments of long-term borrowings under credit facility	(55,000)	-
Payments for loan and debt issue costs	(2,905)	(161)
Purchase of treasury units	(17)	(4,920)
Net cash flows provided by financing activities	166,822	54,214
Net increase (decrease) in cash and cash equivalents	27,105	(69,230)
Cash and cash equivalents, beginning of period	96,067	123,779
Cash and cash equivalents, end of period	$ 123,172	$ 54,549
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 31,326	$ 43,831
Non-cash investing and financing activities:		
Change in accrued capital expenditures in accrued drilling cost and accrued liabilities	$ 28,900	$ (4,385)
Additions to asset retirement obligation	1,721	1,932
Asset retirement obligation associated with properties exchanged or sold	(48)	(1,165)
Change in accrued loan origination costs	(182)	(362)
Accrued distribution to limited partner	6,560	-
Change in accrued treasury unit purchase	(29)	(4,920)

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

A. Organization and Nature of Operations

CrownRock, L.P. ("the Partnership") is a Delaware limited partnership formed on February 14, 2007 by affiliates of CrownQuest Operating, LLC ("CrownQuest"), an independent oil and natural gas producer who is a wholly-owned subsidiary of one of the members of the Partnership's ultimate general partner, and Lime Rock Partners, a private equity firm focused on the oil and natural gas industry ("Lime Rock"). The Partnership's principal business is the acquisition, development, exploration and production of oil and natural gas properties primarily located in the Permian Basin of West Texas.

On December 21, 2017, affiliates of CrownQuest's management team and Lime Rock formed CrownRock Holdings, L.P., a Delaware limited partnership ("Holdings"). Effective January 1, 2018, the Partnership merged with a subsidiary of Holdings, and, as a result, Holdings is now the sole limited partner and holder of 100% of the Partnership's limited partnership interests. The Partnership admitted Holdings as its sole limited partner by issuing 100 new limited partnership units and cancelling all its other limited partner interests comprised of Class A, B, C, D and E limited partnership units. Holdings issued equivalent units of equivalent classes to the former limited partners of the Partnership. As the ownership of the Partnership was identical prior to and after the merger, it was considered a transaction between entities under common control.

B. Summary of Significant Accounting Policies

Organization and principles of consolidation. The Partnership is the sole member of Roddy Production Company, LLC ("Roddy") and a 51% owner of Abajo Gas Transmission Company, LLC ("Abajo"). The consolidated financial statements include the accounts of the Partnership and its majority-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

On July 7, 2011, CrownRock Finance, Inc. ("CrownRock Finance"), a Delaware corporation and wholly-owned subsidiary of the Partnership, was organized for the sole purpose of serving as co-issuer of senior notes and it is currently a co-issuer of $1.185 billion of senior notes due October 15, 2025. CrownRock Finance currently has, and will have, no operations, assets or liabilities other than with respect to the notes or other debt securities the Partnership may issue in the future. See Note O – Supplemental Guarantor Information and Note M – Long-term debt.

On February 28, 2014, Canvasback Properties, LLC ("Canvasback"), a Texas corporation and wholly-owned subsidiary of the Partnership, was organized for the purpose of constructing, owning and managing an office building in Midland, Texas, which is the Partnership's headquarters, and a field operations office in Martin County, Texas.

Interim financial statements. These consolidated financial statements as of September 30, 2018 and for the three and nine months ended September 30, 2018 and 2017 are unaudited. In the opinion of management, such financial statements include the adjustments and accruals, all of which are of a normal recurring nature, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results for a full year. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission. These unaudited consolidated financial statements should be read in conjunction with the Partnership's annual financial statements for the year ended December 31, 2017.

Cash and cash equivalents. The Partnership considers all highly liquid instruments with original maturities of three months or less to be cash equivalents.

B. Summary of Significant Accounting Policies (Continued)

Accounts receivable and allowance for doubtful accounts. CrownQuest markets most of the Partnership's oil and natural gas to various customers. Oil and natural gas sales receivables are generally unsecured. CrownQuest monitors exposure to these customers primarily by reviewing credit ratings, financial statements and payment history. CrownQuest extends credit terms based on their evaluation of each customer's creditworthiness. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Partnership does not have any off balance sheet credit exposure related to its customers.

Oil and natural gas properties. The Partnership uses the successful efforts method of accounting for its investments in oil and natural gas properties. Under such method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized.

Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized but charged to expense if and when the well is determined not to have found reserves in commercial quantities. If the unproved properties are determined to be productive, the related costs are transferred to proved oil and natural gas properties.

Capitalized costs of producing oil and natural gas properties, net of estimated salvage values, are depreciated and depleted by the units-of-production method. Acquisition and leasehold costs of proved properties are amortized on the basis of total proved reserves, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resulting gain or loss is recognized. On the sale or retirement of a partial unit of proved property, the costs, net of proceeds, are charged to accumulated depreciation, depletion, and amortization, unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in the statement of operations. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of costs without recognizing any gain or loss. See Note N – Exchanges for additional information.

On exchanges of oil and natural gas assets with third parties, the Partnership reviews the transactions for certain key aspects that may have a significant impact on its accounting. Exchange transactions that only involve unproved properties are generally measured on recorded values rather than fair values. Thus, no gain or loss is recognized. Conversely, exchange transactions involving proved developed properties must be analyzed for possible business combinations and commercial substance. These aspects, along with others, dictate whether the Partnership records exchanges at recorded values or fair values and whether gains or losses should be recognized.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. The Partnership reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. The Partnership assesses impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas 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. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. Unproved properties are assessed for impairment at least annually on a property-by-property basis, and any impairment is charged to expense. If the unproved properties are determined to be productive, the related costs are transferred to proved oil and natural gas properties.

B. Summary of Significant Accounting Policies (Continued)

The Partnership periodically reviews its proved and unproved oil and natural gas properties that are sensitive to oil and natural gas prices for impairment. Impairment expense is caused primarily due to declines in commodity prices and well performance.

The leasehold acreage quantity information disclosed throughout these consolidated financial statements is unaudited.

Deferred loan costs. Costs incurred in connection with the issuance of debt are deferred and recorded on the balance sheet. Costs associated with the bank credit facility are included in noncurrent assets; costs associated with the senior notes and the Canvasback construction loan are included as direct deductions from the carrying amounts of the debt liabilities. Deferred loan costs are stated net of amortization, which is computed using the straight-line method and approximates the effective interest method. The debt issue costs are amortized to interest expense over the life of the debt.

Future amortization expense of deferred loan costs at September 30, 2018 was as follows:

In thousands		
Remaining 2018	$	780
2019		3,118
2020		2,225
2021		1,927
2022		1,927
Thereafter		5,396
Total	$	15,373

Equity method investment. In August 2017, the Partnership executed a Limited Liability Company Agreement in which it became a voting equity member of a newly-formed oil and natural gas service company, Silvertip Completion Services, LLC ("Silvertip"), that provides wireline and pump down services to exploration and production companies operating in the Permian Basin. In exchange for the equity units in the service company, through September 30, 2018, the Partnership has contributed $8.7 million in cash (including $1.8 million during the nine months ended September 30, 2018) and committed up to an additional $5.3 million payable upon the Partnership receiving capital calls from Silvertip. The Partnership's capital commitment to Silvertip expires on August 31, 2020. The Partnership currently owns approximately 31% of all outstanding voting equity units and is accounting for the investment utilizing the equity method of accounting. The Partnership's investment in Silvertip is included in other assets on the balance sheet. During the nine months ended September 30, 2018, CrownRock recognized income of $688 thousand associated with its share of the net income of Silvertip. The income is included in other income (expense), net on the statements of income. All intra-entity income and losses have been eliminated.

Use of estimates. Preparing financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The financial statements are based on a number of significant estimates including oil and natural gas reserve quantities and values, which are the basis for oil and natural gas properties acquired or exchanged, calculation of depletion, depreciation and amortization, asset retirement obligations, and impairment of oil and natural gas properties.

Fair value. Fair value is defined as 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:

B. Summary of Significant Accounting Policies (Continued)

Level 1. Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Partnership considers active markets to be 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 the Partnership values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category are non-exchange traded derivatives such as over-the-counter commodity price swaps. The Partnership's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Partnership utilizes its counterparties' valuations to assess the reasonableness of its prices and valuation techniques.

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). Items included in this category are asset retirement obligations, asset impairments and asset acquisitions and exchanges.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Partnership'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.

Unit-based compensation. From time to time, Holdings exchanges its equity instruments for services provided by the officers and employees of CrownQuest that are based on the fair value of Holdings' equity instruments or that may be settled by the issuance of those equity instruments in exchange for the services. The cost of the services received in exchange for equity instruments is measured based on the grant-date fair value of those instruments. The compensation costs associated with the services provided is treated as a deemed capital contribution from Holdings to the Partnership. That cost is recognized by the Partnership as compensation expense over the requisite service period (generally the vesting period).

New accounting pronouncements issued but not yet adopted. In August 2018, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2018-13, "Fair Value Measurement (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement", as part of the FASB's disclosure framework project to improve the effectiveness of disclosures in the notes to the financial statements. These amendments modify the disclosure requirements in Topic 820 by removing certain disclosures, modifying certain existing disclosures, and adding new disclosures. The amendments in this update apply to all entities that are required under existing generally accepted accounting principles ("GAAP") to make disclosures about recurring or nonrecurring fair value measurements. Certain of the disclosures that are required by the amendments in this update are not required for nonpublic entities. This new guidance is effective for the Partnership for fiscal years beginning after December 15, 2019. An entity is permitted to early adopt any removed or modified disclosures upon issuance of ASU No. 2018-13 and delay adoption of the additional disclosures until their effective date. The Partnership is currently evaluating the impact of ASU No. 2018-13 on its consolidated financial statements.

B. Summary of Significant Accounting Policies (Continued)

In January 2017, the FASB issued ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired is concentrated in a single asset or a group of similar assets, the set is not a business. This new guidance is effective for the Partnership for annual periods beginning after December 15, 2018, and early adoption is allowed. The Partnership is currently evaluating the impact of ASU No. 2017-01 on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)". The new standard establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for the Partnership for fiscal periods beginning after December 15, 2019, including interim periods within those fiscal periods. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership is currently evaluating the impact of the pending adoption of ASU No. 2016-02 on its consolidated financial statements.

In July 2018, the FASB issued ASU No. 2018-11, "Leases (Topic 842): Targeted Improvements". These amendments provide entities with an additional (and optional) transition method to adopt the new leases standard (ASU No. 2016-02). Entities currently are required to adopt the new leases standard using a modified retrospective transition method. Under the new transition method provided by ASU No. 2018-11, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with current GAAP (Topic 840, Leases). ASU 2018-11 also provides lessors with a practical expedient, by class of underlying asset, to not separate nonlease components from the associated lease component and, instead, to account for those components as a single component if the nonlease components otherwise would be accounted for under the new revenue guidance (Topic 606) and certain criteria are met. The amendments in this update related to transition relief on comparative reporting at adoption affect all entities with lease contracts that choose the additional transition method, while the amendments in this update related to separating components of a contract affect only lessors whose lease contracts qualify for the practical expedient. Since the Partnership has not yet adopted ASU No. 2016-02, this new guidance is effective for the Partnership at the same effective date of ASU No. 2016-02, which is for fiscal years beginning after December 15, 2019, including interim periods within those fiscal periods. The Partnership is currently evaluating the impact of ASU No. 2018-11 on its consolidated financial statements.

In January 2018, the FASB issued ASU No. 2018-01, "Leases, Targeted Improvements", which allows entities to apply the new leases standard established by ASU No. 2016-02 at the adoption date and recognize a cumulative-effect adjustment to retained earnings in the period of adoption. Under the original guidance in ASU No. 2016-02, a modified retrospective method was required when presenting comparative financial information, including periods containing leases that existed or expired before the adoption date of ASU No. 2016-02 and that were not previously accounted for as leases under the original "Leases (Topic 840)" accounting standard. The amendments in ASU No. 2018-01 also provide an optional practical expedient under certain circumstances to not separate nonlease components from the associated lease and continue to account for the lease and the non-lease components together. Lastly, the amendments in ASU No. 2018-01 provide an optional practical expedient for entities to not evaluate land easements that existed or had expired prior to the adoption of ASU No. 2016-02 that were not previously accounted for as leases under the original "Leases (Topic 840)" accounting standard. As this guidance serves as an amendment to ASU 2016-02, it is effective for the Partnership for fiscal periods beginning after December 15, 2019. The Partnership is currently evaluating the impact of ASU No. 2018-01 on its consolidated financial statements.

B. Summary of Significant Accounting Policies (Continued)

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers", which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP. The implementation of this standard is to be done using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosure). Early application of the guidance in this ASU is permitted with certain restrictions.

In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers", which deferred the original effective dates of ASU 2014-09 for the Partnership to annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019. The Partnership's task force, formed in June 2017, is continuing to evaluate the impact of its pending adoption of ASU 2014-09 on its consolidated financial statements. The task force has completed its accumulation of general and upstream oil and gas industry-specific information and has completed its compilation of information about the Partnership's existing contracts with customers. The task force is currently drafting its summary and conclusion documentation and expects to complete its work in the fourth quarter of 2018 and determine the method by which it will adopt the standard in 2019.

Subsequent events. The Partnership performed an evaluation of subsequent events through November 9, 2018, which is the date the consolidated financial statements were available to be issued.

C. Oil and Natural Gas Properties

The following table sets forth information concerning the Partnership's oil and natural gas properties as of September 30, 2018 and December 31, 2017:

	September 30, 2018	December 31, 2017
	(In thousands)	
Proved oil and natural gas properties	$ 2,554,612	$ 2,053,382
Unproved oil and natural gas properties	272,518	211,637
Less accumulated depreciation, depletion, amortization and impairment	(760,709)	(609,843)
Net oil and natural gas properties	$ 2,066,421	$ 1,655,176

During the three months ended September 30, 2018, the Partnership recognized exploration costs of approximately $1.6 million primarily comprised of approximately $0.8 million of dry hole expense of one oil and natural gas well on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas and approximately $0.7 million of expired oil and natural gas leases in the Permian Basin of Texas, which were determined to have no future development potential. During the three months ended September 30, 2017, the Partnership recognized exploration costs of approximately $2.6 million comprised of expired oil and natural gas leases in the Permian Basin of Texas, which were determined to have no future development potential. During the nine months ended September 30, 2018, the Partnership recognized exploration costs of approximately $3.9 million primarily comprised of approximately $3.0 million of dry hole expense and $0.8 million of expired oil and natural gas leases in the Permian Basin of Texas, which were determined to have no future development potential. During the nine months ended September 30, 2017, the Partnership recognized exploration costs of approximately $10.2 million comprised of approximately $9.0 million of expired oil and natural gas leases in the Permian Basin of Texas, which were determined to have no future development potential.

C. Oil and Natural Gas Properties (Continued)

During the three and nine months ended September 30, 2018, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of approximately $0.8 million and $2.2 million, respectively, to provide as estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire. During the three and nine months ended September 30, 2017, the Partnership recognized a non-cash charge against earnings of approximately $0.2 million and $2.3 million, respectively, related to impairment of producing oil and natural gas properties in the Permian Basin of Texas and New Mexico for which net capitalized costs exceeded estimated undiscounted future net cash flows. Additionally, during the three and nine months ended September 30, 2017, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.7 million and $2.2 million, respectively to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire.

See Note I – Fair Value for discussion of proved property impairments recorded during the three and nine months ended September 30, 2017. No proved property impairments were recorded during the nine months ended September 30, 2018.

The Partnership initiated a horizontal well drilling program in January 2015. The Partnership capitalizes exploratory horizontal and vertical well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory horizontal well costs included in unproved oil and natural gas properties pending the determination of proved reserves at September 30, 2018 were $10.8 million. All of these costs are from wells drilled during the nine months ended September 30, 2018.

D. Other Property and Equipment

The following table sets forth the Partnership's other property and equipment as of September 30, 2018 and December 31, 2017:

	September 30, 2018	December 31, 2017
	(In thousands)	
Land	$ 24,162	$ 23,000
Water rights	11,872	11,872
Construction in progress - office building	-	1,620
Construction in progress - gathering systems	1,408	1,211
Office buildings	26,050	23,808
Equipment	56	56
Gathering systems	39,754	37,612
Pipeline and gathering facilities	11,714	11,714
Less accumulated depletion, depreciation and impairment	(20,025)	(17,484)
Net other property and equipment	$ 94,991	$ 93,409

Land and water rights. The Partnership owns surface acreage located in various portions of the Partnership's core northern Midland Basin leasehold acreage. The Partnership's purchase of surface acreage is part of its ongoing strategy to cost-effectively support its horizontal drilling program in the Midland Basin. The Partnership also owns the water rights attached to certain portions of the surface acreage. The ownership of these water rights allows the Partnership to drill water wells and construct water storage facilities on the surface that will support the drilling and completion of its future horizontal oil and natural gas wells on or in close proximity to the surface acreage. In July 2018, the Partnership began depleting its capitalized water rights using the units-of-production method. For the three months ended September 30, 2018, $0.4 million was recorded to depletion expense.

Office buildings. Canvasback owns a 60,800 square feet office building in Midland, Texas which is the Partnership's headquarters. Canvasback also owns a 30,250 square feet building in Martin County, Texas which is the Partnership's field operations headquarters.

D. Other Property and Equipment (Continued)

In June 2017, Canvasback commenced construction of a 15,140 square feet extension of the Partnership's field operations headquarters building in Martin County, Texas. The office building was completed in February 2018.

Gathering systems. The Partnership owns a low-pressure gas gathering system that covers approximately 110 square miles in western Howard and northern Glasscock Counties, Texas. It is designed to gather up to 50,000 Mcf per day of casinghead gas from CrownQuest operated and non-operated oil and natural gas wells in close proximity. It consists of approximately 125 linear miles of high-density polyethylene pipe and connects to a large midstream company's gathering system at three compressor sites.

The Partnership owns a gas, oil, and produced water gathering system that covers approximately 25 square miles in Midland County, Texas. The gas gathering system is designed to gather up to 50,000 Mcf per day of casinghead gas from CrownQuest operated wells near its proximity, while the oil and produced water gathering systems, which parallel the gas system, are designed to gather a combined 50,000 barrels per day of produced liquids. The three systems contain approximately 125 linear miles of high-density polyethylene pipe and connect CrownQuest operated leases to a large midstream company's gas pipeline, oil purchasers, and salt water disposal systems in the area.

E. Asset Retirement Obligations

The Partnership records a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalizes an equal amount as part of the cost of their related oil and natural gas properties. Asset retirement obligations are initially recorded at fair value and assessed for revisions periodically thereafter. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs and well life. The inputs are calculated based on historical data as well as current estimated costs.

The following table summarizes the changes in the Partnership's asset retirement obligation during the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)		(In thousands)	
Balance, beginning of period	$ 21,525	$ 19,389	$ 20,231	$ 18,677
Liabilities incurred during the period	812	361	1,721	1,932
Liabilities settled during the period	(24)	(489)	(59)	(637)
Liabilities associated with properties exchanged	-	(49)	(48)	(1,165)
Accretion expense	249	212	717	617
Balance, end of period	22,562	19,424	22,562	19,424
Less current portion	(262)	(208)	(262)	(208)
Non-current portion	$ 22,300	$ 19,216	$ 22,300	$ 19,216

Asset retirement obligations for natural gas pipeline facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured since it is impossible to estimate the future settlement dates of such obligations.

F. Credit and Counterparty Risk

Cash and cash equivalents are maintained at financial institutions and, at times, balances may exceed federally insured limits. Amounts on deposit in excess of federally insured limits at September 30, 2018 approximated $122.3 million. The Partnership treats all investment securities with original maturities of 90 days or less as cash equivalents.

G. Related Party Transactions

At September 30, 2018, the Partnership has a net derivative liability of $66.5 million, a portion of which is subject to its counterparties' credit and performance risk. The Partnership routinely monitors the creditworthiness of its counterparties but does not require collateral or other security to support derivative instruments. However, agreements with the counterparties contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under derivative contracts with the amount due from the defaulting party under derivative contracts. As a result of the netting provisions, the Partnership's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparty under the derivative contracts.

Related party operator of oil and natural gas properties. Most of the Partnership's properties are operated by CrownQuest. As of September 30, 2018, and December 31, 2017, aggregate related party accounts payable and accrued liabilities owed to CrownQuest in the normal course of the Partnership's oil and natural gas property operations were $34.0 million and $7.1 million, respectively, related specifically to accrued drilling costs on wells being drilled and completed as of period end and accrued lease operating expenses. Further, with respect to the properties operated by CrownQuest, at September 30, 2018 and December 31, 2017, related party accounts receivable outstanding in the normal course of business related primarily to accrued oil and natural gas sales, fresh water sales and water disposal fees were $77.1 million and $43.5 million, respectively.

Management fees paid to related party. Pursuant to an administrative agreement, the Partnership pays CrownQuest a monthly management fee based upon an annual budget approved by the Partnership. The Partnership is required to reimburse CrownQuest for substantially all costs, which include employee expense, rent expense, license fees, insurance cost, general office expenses, depreciation expense related to capitalized equipment, third party charges incurred for the benefit of the Partnership, and any and all expenses incurred by CrownQuest in providing support to the Partnership net of any amounts received under any operating agreements. For the three and nine months ended September 30, 2018 the Partnership recorded management fees of $4.6 million and $14.2 million, respectively, in general and administrative expenses. For the three and nine months ended September 30, 2017 the Partnership recorded management fees of $3.8 million and $11.8 million, respectively, in general and administrative expenses.

Royalty and other payments to affiliates. CrownQuest, as the operator of the Partnership's properties, periodically makes various types of payments to companies affiliated with CrownQuest. During the nine months ended September 30, 2018 and 2017, payments of $23.4 million and $10.8 million, respectively, were made by the operator to affiliates for royalty interests, lease bonuses and extensions, surface acquisitions, surface damages, water purchases and water disposal with respect to such properties. Payments for the nine months ended September 30, 2018 and 2017, include amounts paid to a CrownQuest-affiliated royalty company formed in March 2016. This royalty company acquired royalty interests from third parties on properties operated by CrownQuest and in which the Partnership owns working interests. Payments to this royalty company for the nine months ended September 30, 2018 were $17.6 million primarily for royalty interests on properties operated by CrownQuest. Payments to this royalty company for the nine months ended September 30, 2017 were $7.8 million including $4.1 million for royalty interests and $3.5 million for surface acquisitions done jointly in a transaction in which the royalty company acquired the associated royalty interests.

CrownQuest payments to CrownRock. As a result of its ownership of surface acreage, water rights and infrastructure, the Partnership periodically receives payments from CrownQuest for surface damages, fresh water purchases and water disposal. During the nine months ended September 30, 2018, CrownQuest paid the Partnership $5.0 million for these transactions. There were no transactions of these types during the nine months ended September 30, 2017.

G. Related Party Transactions (Continued)

Oil and natural gas property lease from an officer of CrownQuest. A family partnership controlled by Mr. Robert W. Floyd, President of CrownQuest and Director of the Partnership's general partner, CrownRock GP, LLC, and his wife has royalty interests in certain properties that the Partnership is developing in the Permian Basin. During the nine months ended September 30, 2018 and 2017, the Partnership paid $13 thousand and $5 thousand, respectively, for royalty interests.

In a series of transactions beginning in August 2013, the Partnership entered into oil and natural gas property lease agreements with several relatives of Mr. Floyd and a family limited liability company in which Mr. Floyd owns a 33 1/3% interest. The leases are for unproved acreage in the Midland Basin in West Texas. The Partnership is currently developing this acreage. During the nine months ended September 30, 2018, the Partnership paid $3.6 million for royalty interests, surface damages and water purchases. During the nine months ended September 30, 2017, the Partnership paid $2.7 million for royalty interests and lease bonuses.

In June 2014, the Partnership entered into an oil and natural gas property lease agreement with a relative of Mr. Floyd for unproved acreage in the Midland Basin in West Texas. The Partnership is currently developing this acreage. The Partnership agreed to pay Mr. Floyd's relative an aggregate of $2.78 million. As of September 30, 2018, the remaining obligation is $555,000 which is included in other current liabilities in the consolidated balance sheet. Such amount will be paid in January 2019.

Related party owner and operator of aircraft used by CrownQuest. During 2012, Mr. Floyd and EnerQuest Oil & Gas Ltd. ("EOG"), an entity affiliated with the Partnership, formed an entity named EnerQuest Aviation Partners, LLC ("Aviation Partners") and acquired 50% of an aircraft with the other 50% belonging to a third party individual. The aircraft is managed by Crown Eye Partners, LLC ("Crown Eye") which is owned 60% by Aviation Partners and 40% by the same third party individual. During the nine months ended September 30, 2018, Aviation Partners and the third party individual sold their interest in the original aircraft and jointly acquired a new aircraft, with a 60%/40% ownership allocation, respectively. This aircraft is available for use by CrownQuest employees when conducting business on behalf of the Partnership. The Partnership pays CrownQuest's usage of the aircraft under the terms of the administrative support agreement. During the nine months ended September 30, 2018, CrownQuest paid Crown Eye $77 thousand for usage of the aircraft for 27.1 hours at an average cost of $2,827 per hour. During the nine months ended September 30, 2017, CrownQuest paid Crown Eye $121 thousand for usage of the aircraft for 59.2 hours at an average cost of $2,051 per hour.

Equity investment provider of oilfield services to CrownQuest. Silvertip provides wireline and pump down services to companies operating in the Permian Basin, including CrownQuest. CrownQuest procures these services for wells in which the Partnership has working interests. During the nine months ended September 30, 2018, Silvertip billed CrownQuest $15.2 million for services provided on Partnership-owned properties. The Partnership has eliminated all intra-entity income and losses related to these services. Silvertip did not provide any services to CrownQuest during the nine months ended September 30, 2017.

H. Derivative Financial Instruments

The Partnership has entered into derivative contracts with counterparties that are lenders under its revolving credit facility to manage its exposure to commodity price fluctuations associated with a portion of the Partnership's oil and natural gas production.

The Partnership does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Partnership records all derivative instruments on the consolidated balance sheets at fair value. The Partnership nets derivative assets and liabilities for counterparties where the Partnership has a legal right of offset. Further, the Partnership reflects changes in the fair value of its derivative instruments currently in its consolidated statements of operations as they occur.

H. Derivative Financial Instruments (Continued)

Commodity derivative contracts at September 30, 2018. The following table sets forth the Partnership's outstanding commodity derivative contracts, by quarter of settlement, at September 30, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2018:					
Volume (Bbl)				2,162,000	2,162,000
Price per Bbl				$ 67.81	$ 67.81
2019:					
Volume (Bbl)	2,178,000	2,275,000	2,944,000	2,944,000	10,341,000
Price per Bbl	$ 60.94	$ 62.34	$ 62.26	$ 62.52	$ 62.07
2020:					
Volume (Bbl)	1,456,000	546,000	-	-	2,002,000
Price per Bbl	$ 66.21	$ 65.98	$ -	$ -	$ 66.15
Oil Basis Swaps: (b)					
2018:					
Volume (Bbl)				1,610,000	1,610,000
Price per Bbl				$ (8.82)	$ (8.82)
2019:					
Volume (Bbl)	1,890,000	2,275,000	2,944,000	2,944,000	10,053,000
Price per Bbl	$ (0.35)	$ (0.35)	$ (1.00)	$ (1.00)	$ (0.73)
2020:					
Volume (Bbl)	2,275,000	2,275,000	2,760,000	2,760,000	10,070,000
Price per Bbl	$ (0.62)	$ (0.62)	$ (0.67)	$ (0.67)	$ (0.65)

(a) The index prices for the oil price swaps are based on the NYMEX - West Texas Intermediate monthly average futures price.
(b) The basis differential price is between Midland - WTI and Cushing - WTI.

The following table summarizes the activity in the Partnership's derivative instruments, for each of the periods indicated:

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Year Ended December 31, 2017
	(In thousands)	(In thousands)	(In thousands)
Net asset, beginning of period	$ 57,803	$ 157,049	$ 157,049
Cash settlement receipts	(21,390)	(91,877)	(108,266)
Changes in fair value of derivatives	(102,958)	39,801	9,020
Net asset (liability) end of period	(66,545)	104,973	57,803
Less current asset (liability)	(44,255)	84,207	59,044
Non-current asset (liability)	$ (22,290)	$ 20,766	$ (1,241)

H. Derivative Financial Instruments (Continued)

Our commodity derivatives are presented on a net basis in "derivative instruments" on the Condensed Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Condensed Consolidated Balance Sheets for the periods indicated (in thousands):

	Nine Months Ended September 30, 2018		
	Fair Value	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Fair Value Presented in the Consolidated Balance Sheet**
Derivatives not designated as hedging instruments			
Asset Derivatives:			
Commodity price derivatives	$ 55,411	$ (55,411)	$ -
Liability Derivatives:			
Commodity price derivatives	$ (121,956)	$ 55,411	$ (66,545)

	Year Ended December 31, 2017		
	Fair Value	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Fair Value Presented in the Consolidated Balance Sheet**
Derivatives not designated as hedging instruments			
Asset Derivatives:			
Commodity price derivatives	$ 67,747	$ (8,703)	$ 59,044
Liability Derivatives:			
Commodity price derivatives	$ (9,944)	$ 8,703	$ (1,241)

I. Fair Value

Assets and Liabilities Measured at Fair Value on a Recurring Basis. The following table sets forth by level within the fair value hierarchy the Partnership's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2018 and December 31, 2017:

	Fair value measurements using			
Description	**Quoted prices in active markets (Level 1)**	**Other observable inputs (Level 2)**	**Unobservable inputs (Level 3)**	**Fair Value**
		(In thousands)		
Oil and oil basis swaps	$ -	$ (66,545)	$ -	$ (66,545)
Total as of September 30, 2018	$ -	$ (66,545)	$ -	$ (66,545)
Oil and oil basis swaps	$ -	$ 57,803	$ -	$ 57,803
Total as of December 31, 2017	$ -	$ 57,803	$ -	$ 57,803

I. Fair Value (Continued)

The Partnership estimates the fair values of the swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate for those commodities for which published forward pricing is readily available. For those commodity derivatives for which forward commodity price curves are not readily available, the Partnership estimates, with the assistance of third-party pricing experts, the forward curves as of the date of the estimate. Using a discounted cash flow model, the determination of the fair values above incorporates various factors including the impact of the Partnership's non-performance risk, the credit standing of the counterparties involved in the Partnership's derivative contracts, NYMEX future prices and interest rates.

The following table represents the carrying amounts and fair values of the Partnership's financial instruments at September 30, 2018 and December 31, 2017:

	September 30, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In thousands)		
Assets:				
Derivative instruments	$ -	$ -	$ 59,044	$ 59,044
Liabilities:				
Derivative instruments	$ (66,545)	$ (66,545)	$ (1,241)	$ (1,241)

Cash and cash equivalents, accounts receivable, accounts payable and interest payable. The carrying amounts approximate fair value due to the short maturity of these instruments.

Credit facility. The fair value of the revolving credit facility borrowings approximate the carrying amounts based upon interest rates currently available to the Partnership for borrowings with similar terms (Level 2).

Senior notes. The fair value of the Partnership's 5.625% Senior Notes due 2025 was $1,156.9 million at September 30, 2018. Such fair value was determined using Level 2 inputs including quoted period end market prices.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-recurring fair value measurements include certain nonfinancial assets and liabilities as may be acquired in a business combination or property exchange and thereby measured at fair value; impaired oil and natural gas property assessments; unit-based compensation; and the initial recognition of asset retirement obligations for which fair value is used. These estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Partnership has designated these estimates as Level 3.

Impairments of long-lived assets. The Partnership periodically reviews for impairment its long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. During the three and nine months ended September 30, 2018, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.8 million and $2.2 million, respectively, to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire. During the three and nine months ended September 30, 2017, the Partnership recognized non-cash charges against earnings of approximately $0.2 million and $2.3 million, respectively, related to impairment of producing oil and natural gas properties in the Permian Basin of Texas and New Mexico for which net capitalized costs exceeded estimated undiscounted future net cash flows. Additionally, during the three and nine months ended September 30, 2017, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.7 million and $2.2 million, respectively, to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership allowed to expire.

Unit-based compensation. See fair value disclosures in Footnote L – Incentive Plans.

J. Commitments and Contingencies

As part of the administrative agreement between the Partnership and CrownQuest, the Partnership reimburses CrownQuest for rent expense. At September 30, 2018, CrownQuest was party to three operating leases for office space:

(a) Lease agreement dated June 19, 2014 with Canvasback as lessor on the 59,134 square feet headquarters office in Midland County, Texas. The lease agreement was effective December 1, 2015 and terminates on June 30, 2026.
(b) Lease agreement dated October 8, 2015 with Canvasback as lessor on the 30,250 square feet field operations office and 4,000 square feet barn in Martin County, Texas. The lease agreement was effective September 1, 2015 and terminates on September 1, 2020.
(c) Lease agreement dated April 18, 2018 with Canvasback as lessor on the 15,140 square feet extension of the field operations office in Martin County, Texas. The lease agreement was effective February 1, 2018 and terminates on September 1, 2020.

For the nine months ended September 30, 2018 and 2017, the Partnership reimbursed CrownQuest for rent expense for office space of $1.7 million and $1.6 million, respectively, included in the monthly management fee. The rent expense relates to the Canvasback leases which are eliminated in consolidation.

CrownQuest has entered into contracts to secure the availability of drilling rigs and are subject to payments in accordance with the contracts based on the utilization of the drilling rigs.

From time to time, the Partnership is party to ordinary routine litigation incidental to the business. The Partnership believes that the results of such proceedings will not have a material adverse effect on its consolidated financial statements

K. Partners' Capital

CrownRock, L.P. is a privately held limited partnership formed in the State of Delaware on February 14, 2007. The ultimate general partner has the exclusive right to manage the business of the Partnership and has all powers and rights necessary or advisable to effectuate and carry out the purposes and business of the Partnership.

Effective January 1, 2018, the Partnership merged with a subsidiary of Holdings. As a result of this merger, the Partnership and its general partner became wholly-owned subsidiaries of Holdings. The Partnership admitted Holdings as its sole limited partner by issuing 100 new limited partnership units and cancelling all its other limited partner interests comprised of Class A, B, C, D and E limited partnership units. Holdings issued equivalent units of equivalent classes to the former limited partners of the Partnership. The only outstanding units of the Partnership at September 30, 2018 are the 100 limited partnership units held by Holdings. Additionally, effective January 1, 2018, the Partnership executed the Second Amended and Restated Limited Partnership Agreement to provide for sole control and management of the Partnership by the general partner and the simplification of the governance of the Partnership.

K. Partners' Capital

After January 1, 2018, distributions are being made solely to Holdings as the Partnership's sole limited partner. On January 4, 2018, Holdings issued 475,000 Series A Preferred units to investors for a purchase price of $1,000 per unit. On April 13, 2018, Holdings issued 35,000 Series A Preferred Units to investors for a purchase price of $1,000 per Preferred Unit. Additionally, on May 15, 2018, Holdings issued 40,000 Series A Preferred Units for a purchase price of $1,000 per Preferred Unit. Holdings must make quarterly tax distributions in cash to the holders of its Series A Preferred Units beginning with the quarter ending March 31, 2018. The amount of such tax distributions for 2018 is expected to be approximately $24.4 million. Since Holdings' only asset is its ownership of the Partnership and the Partnership's general partner, the funds Holdings requires to pay the quarterly tax distributions will be obtained from the Partnership paying quarterly distributions to Holdings. To provide Holdings with funds required to make its quarterly tax distribution, the Partnership distributed $11.3 million during the nine months ended September 30, 2018 and $6.6 million on October 15, 2018 to Holdings. The Partnership's credit facility and the indenture governing its 2025 Senior Notes have restrictive covenants limiting dividends and distributions (See Note M – Long-term Debt). The Partnership estimates that it can pay the necessary quarterly tax distributions to Holdings within the limits of these two agreements.

Based upon the provisions of the indenture governing the Partnership's senior notes, as of September 30, 2018, the Partnership is allowed to make distributions to Holdings of approximately $267.7 million.

L. Incentive Plans

Defined contribution plan. CrownQuest sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. Currently, CrownQuest matches 100% of employee contributions, not to exceed 5% of the employee's annual base salary. The Partnership's contributions to the plan, through its reimbursement to CrownQuest pursuant to the terms of an administrative support agreement, were approximately $822 thousand and $665 thousand for the nine months ended September 30, 2018 and 2017, respectively.

Unit incentive plan. The Second Amended and Restated Limited Partnership Agreement of Holdings dated January 4, 2018 (the "Holdings LP Agreement") provides for the granting of restricted unit awards to employees of CrownQuest in order to recognize and reward significant contributions. The incentive unit program is structured such that the unit awards are Class D LP Units and Class E LP Units and represent a profits interest in Holdings. In designating such units, the Holdings LP Agreement authorized a maximum of 500,000 Class D Units and 300,000 Class E LP Units to be issued from time to time as determined by Holding's general partner (the Partnership's "ultimate general partner"). The unit incentive plan was previously administered by the Partnership prior to the merger with Holdings. The terms and conditions of the plan remain unchanged prior to and after the merger, except any restricted units are now issued by Holdings.

During the nine months ended September 30, 2018, Holdings' general partner approved aggregate grants of 108,500 of Class E LP Units to non-officer employees of CrownQuest, subject to certain restrictions as set forth in the respective restricted unit agreements between Holdings and each such CrownQuest employee. No grants of Class D LP Units were made during the nine months ended September 30, 2018. The restrictions lapse with respect to 100% of the restricted units seven years from the date of grant scheduled as no lapsing during the first two years followed by annual lapsing of 20% for the remaining five years. Prior to the merger, the Partnership maintained a similar incentive program. As a result of the merger, a modification occurred to the previous incentive units granted. In accordance with Accounting Standards Codification ("ASC") 718 – Compensation – Stock Compensation, no incremental compensation cost was recognized. During the nine months ended September 30, 2017, the Partnership's general partner approved aggregate grants of 6,000 of Class D LP Units and 5,500 of Class E LP Units to non-officer employees of CrownQuest.

L. Incentive Plans (Continued)

All restricted units are treated as issued and outstanding in the accompanying condensed consolidated balance sheets. If a CrownQuest employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding. A summary of the Partnership's restricted unit awards, comprised of Class D LP Units and Class E LP Units, for the nine months ended September 30, 2018 is presented below:

	Class D LP Units		Class E LP Units	
	Number of Restricted Units	Grant Date Fair Value Per Unit	Number of Restricted Units	Grant Date Fair Value Per Unit
Restricted units:				
Outstanding at December 31, 2017	490,400	$ 57.89	5,000	$ 109.68
Units granted	-	-	108,500	58.57
Units canceled/forfeited	(7,100)	96.29	-	-
Outstanding at September 30, 2018	483,300	$ 57.33	113,500	$ 60.82

The following table summarizes information about unit-based compensation for restricted unit awards, recorded in the Partnership's consolidated financial statements, for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Grant date fair value for awards during the period:				
Employee grants	$ 3,163	$ 603	$ 6,355	$ 2,577
Officer grants	-	-	-	-
Total	$ 3,163	$ 603	$ 6,355	$ 2,577
Unit-based compensation expense from restricted units:				
Employee grants	$ 1,047	$ 830	$ 2,835	$ 2,446
Officer grants	206	208	617	623
Total	$ 1,253	$ 1,038	$ 3,452	$ 3,069

The fair value of the units issued was determined utilizing a valuation provided by an independent third party consulting firm. The consulting firm derived the grant date fair value from this valuation by applying the distribution priority stated in the Holdings' LP Agreement. Such valuation is Level 3 within the fair value hierarchy. This valuation incorporates an income approach, a comparable transaction approach and a market approach to valuing the Partnership with numerous unobservable inputs, including pending and assumed transactions, estimated reserves and production rates, and other factors. Generally, a change in any of these inputs could lead to a change in the valuation of the grants.

L. Incentive Plans (Continued)

Future unit-based compensation expense. The following table reflects future unit-based compensation expense to be recorded for all the unit-based compensation awards that are outstanding at September 30, 2018. This cost is expected to be recognized over a weighted-average period of approximately 3.4 years.

(in thousands)	Future Compensation
Remainder 2018	$ 1,253
2019	3,735
2020	3,145
2021	2,569
2022	2,030
Thereafter	2,840
Total	$ 15,572

M. Long-term Debt

The Partnership's debt consists of the following at September 30, 2018 and December 31, 2017:

	September 30, 2018	December 31, 2017
	(In thousands)	
5.625% unsecured senior notes due 2025	$ 1,185,000	$ 1,000,000
Unamortized original issue discount	(3,093)	-
Unamortized deferred loan costs - senior notes	(13,409)	(12,105)
Construction loan - Canvasback office building	9,558	10,298
Unamortized deferred loan costs - construction loan	(178)	(195)
Total debt	1,177,878	997,998
Less current portion	(1,030)	(993)
Long-term debt	$ 1,176,848	$ 997,005

Credit facility. The Partnership's credit facility, as amended, (the "Credit Facility"), has a maturity date of April 1, 2020. In conjunction with its regular semiannual borrowing base redetermination, effective April 4, 2018, the Partnership elected to maintain a commitment amount of $500 million after being offered a borrowing base of $715 million by the lenders. Commitments from the Partnership's bank group total $1.0 billion. At September 30, 2018 and December 31, 2017, the Partnership had no advances or letters of credit outstanding under the Credit Facility.

Between scheduled borrowing base redeterminations, the Partnership and lenders, if requested by 66 2/3% of the lenders, may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Partnership's option, based on (i) the prime rate of MUFG Union Bank, N.A. ("Union Bank Prime Rate") (5.25% at September 30, 2018) or (ii) Eurodollar rate (substantially equal to the London Interbank Offered Rate). The Credit Facility's interest rates on Eurodollar rate advances and Union Bank Prime Rate advances vary, with interest margins ranging from 250 to 350 basis points and 150 to 250 basis points, respectively, per annum depending on the debt balance outstanding. The Partnership pays commitment fees on the unused portion of the available commitment of 50 basis points per annum.

The Partnership's obligations under the Credit Facility are secured by a first lien on substantially all of its oil and natural gas properties. In addition, all of the Partnership's subsidiaries (excluding Abajo until such time as the Partnership owns 100% of the equity of Abajo) are guarantors, and the equity interests in such subsidiaries have been pledged to secure borrowings under the Credit Facility.

M. Long-term Debt (Continued)

If the outstanding principal balance of the loans under the Credit Facility exceeds the borrowing base at any time, the Partnership has the option to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing five-month period.

The Credit Facility contains various restrictive covenants and compliance requirements, which include:

- maintenance of certain financial ratios, including:
  (i) maintenance of a quarterly ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including all line of credit obligations and any unfunded amounts under the Credit Facility, to be not less than 1.0 to 1.0,
  (ii) maintenance of a quarterly ratio of total funded indebtedness, net of unrestricted cash up to $100 million, to 12-month consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and noncash income and expenses to be no greater than 3.5 to 1.0, and
  (iii) maintenance of a quarterly ratio of 12-month consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and noncash income and expenses to 12-month consolidated interest expense to be not less than 3.0 to 1.0.
- delivery to the lender and maintenance of satisfactory title opinions covering not less than 80% and 85% of the present value of proved oil and natural gas reserves and proved developed producing oil and natural gas reserves, respectively;
- limits on the incurrence of additional indebtedness and certain types of liens;
- restrictions as to investments, mergers, acquisitions and dispositions of assets;
- restrictions on hedging contracts and transactions with affiliates; and
- limits on dividends and distributions. The agreement allows permitted tax distributions. It also allows periodic cash distributions if the Credit Facility usage is equal to or less than 80% of the elected commitment amount and the Partnership's funded indebtedness, net of unrestricted cash up to $100 million, to 12-month consolidated earnings before interest expense, income taxes, depletion, depreciation and amortization, exploration expense and non-cash income and expenses is no more than 2.75 to 1.00. The agreement allows cash distributions in 2018 not to exceed $25 million, irrespective of the limit stated above.

At September 30, 2018, the Partnership was in compliance with all of the covenants under the Credit Facility, as amended.

5.625% Senior Notes due 2025. On October 11, 2017, the Partnership and CrownRock Finance issued $1.0 billion aggregate principal amount of 5.625% senior unsecured notes due 2025 at par (the "2025 Senior Notes"). The Partnership issued the 2025 Senior Notes to fund the tender offers and redemptions of the 7.125% Senior Notes due 2021 (the "2021 Senior Notes") and the 7.75% Senior Notes due 2023 (the "2023 Senior Notes"), pay off advances on the Credit Facility, and for general partnership purposes, including the funding of a portion of its capital development plan. The 2025 Senior Notes mature on October 15, 2025, and interest is paid in arrears semiannually on April 15 and October 15 beginning April 15, 2018. The 2025 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by Roddy and Canvasback. The notes may be redeemed on or after the following dates and at the following redemption prices, expressed as a percentage of principal amount plus accrued and unpaid interest if any, during the periods indicated: October 15, 2020, 104.219%; October 15, 2021, 102.813%; October 15, 2022, 101.406%; October 15, 2023, 100.00%.

On May 22, 2018, the Partnership and CrownRock Finance issued an additional $185 million aggregate principal amount of 2025 Senior Notes at 98.26% of par. The Partnership issued the additional 2025 Senior Notes to pay off advances on the Credit Facility and for general partnership purposes, including the funding of a portion of its capital development plan. These additional notes were fungible with the original notes and are governed by the same indenture and thus contain the same terms and conditions as state above.

M. Long-term Debt (Continued)

The 2025 Senior Notes are general, unsecured senior obligations and are subordinated to all existing and future secured indebtedness, including the Credit Facility. The indenture to the 2025 Senior Notes dated as of October 11, 2017 contains various restrictive covenants which include:

- limits on the incurrence of additional indebtedness and certain types of liens;
- restrictions as to mergers and disposition of assets;
- limits on transactions with affiliates; and
- limits on dividends and distributions. The agreement allows permitted tax distributions and periodic cash distributions up to $150 million plus 50 % of consolidated net income as adjusted for certain non-cash items pursuant to the provisions of the indenture governing the 2025 Senior Notes ("Senior Note Indenture") from July 1, 2017 to the end of the Partnership's most recently ended fiscal quarter.

At September 30, 2018, the Partnership was in compliance with all of the covenants under the indenture to the 2025 Senior Notes.

Construction loan - Canvasback office building. On June 19, 2014, Canvasback entered into a construction loan agreement with a bank (the "Construction Loan") to partially finance the cost of the construction of an office building in Midland, Texas that became the Partnership's headquarters. Advances were made during the period of February 2015 through December 2015 when the final advance was made and the balance outstanding was at its maximum amount available of $12.0 million.

Advances on the Construction Loan bear interest at the fixed rate of 4.75% for the period of June 19, 2014 through June 30, 2020 and then reset and become fixed at the Wall Street Journal published prime rate in effect on July 1, 2020 plus 150 basis points for the period of July 1, 2020 through June 30, 2026.

Payments of interest only were paid monthly during the construction phase beginning September 1, 2014 through February 1, 2016. Construction was completed and the certain conditions of the loan agreement were satisfied in December 2015 to effect the extension of the loan to June 30, 2026. In accordance with the terms of the Construction Loan, commencing on March 1, 2016, payments of principal and interest are due on the first of each month in an amount necessary to fully amortize the loan over its remaining term.

The Construction Loan is secured by a mortgage on the office building. The Partnership unconditionally guarantees Canvasback's payments and performance on the loan.

Principal maturities of debt. The Credit Facility expires in 2020. The 2025 Senior Notes are due in 2025.

Interest expense. The following amounts have been incurred and charged to interest expense for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)		(In thousands)	
Cash payments for interest	$ 750	$ 14,311	$ 31,326	$ 43,831
Amortization of original issue discount	88	139	126	410
Amortization of deferred loan costs	780	762	2,169	2,265
Net changes in accrued interest expense	16,664	540	17,166	539
Total interest expense	$ 18,282	$ 15,752	$ 50,787	$ 47,045

N. Exchanges

If it is deemed value-adding, the Partnership will enter into exchange agreements with third parties to exchange proved and unproved oil and natural gas properties as part of its strategy to consistently pursue financially viable deals to further block-up its acreage and thereby enhance its horizontal well drilling inventory in the Permian Basin. The Partnership completed multiple exchange transactions during the nine months ended September 30, 2018. The significant transactions are shown below.

On August 22, 2018, the Partnership exchanged approximately 2,184 gross (1,849 net) acres of undeveloped leasehold acreage in Glasscock, Martin, and Midland counties, Texas to a third party in exchange for 842 gross (806 net) acres of undeveloped leasehold acreage in Glasscock, Howard, Martin, and Midland counties, Texas. The exchange blocked up the Partnership's acreage position and thereby enhanced its horizontal well inventory in the Midland Basin. The transaction included the exchange of both proved and unproved oil and natural gas properties. No gain or loss was recognized.

On May 15, 2018, the Partnership exchanged approximately 576 gross (221 net) acres of undeveloped leasehold acreage in Midland and Reagan counties, Texas and $0.5 million in cash to a third party in exchange for 1,025 gross (221 net) acres of developed and undeveloped leasehold acreage and working interests in 6 gross (3.6 net) proved developed producing ("PDP") vertical wells in Martin and Howard counties, Texas. The exchange increased the Partnership's working interest in existing CrownQuest-operated wells and blocked up its acreage position and thereby enhanced its horizontal drilling inventory in the Midland Basin. The transaction included the exchange of both proved and unproved oil and natural gas properties. No gain or loss was recognized.

On May 14, 2018, the Partnership exchanged approximately 668 gross (539 net) acres of developed and undeveloped leasehold acreage and working interests in 2 gross (2 net) PDP vertical wells located in Howard, Martin, Dawson, and Borden counties, Texas to a third party in exchange for 564 (460 net) acres of undeveloped leasehold acreage located in Howard County, Texas. The exchange blocked up the Partnership's acreage position and thereby enhanced its horizontal well inventory in the Midland Basin. This transaction included the exchange of both proved and unproved oil and natural gas properties and was accounted for at fair value and, as a result, the Partnership recorded a non-cash gain of $16.1 million.

On May 1, 2018, the Partnership exchanged 2,156 gross (1,458 net) acres of developed and undeveloped leasehold acreage and working interests in 1 gross (.5 net) PDP vertical well and 1 gross (.7 net) proved non-producing vertical well located in Midland and Martin counties, Texas to a third party in exchange for 3,274 gross (1,377 net) acres of undeveloped leasehold acreage located in Martin, Howard, Glasscock, and Midland counties, Texas. The exchange blocked up the Partnership's acreage position and thereby enhanced its horizontal well inventory in the Midland Basin. This transaction included the exchange of both proved and unproved oil and natural gas properties and was accounted for at fair value and, as a result, the Partnership recorded a non-cash gain of $47.1 million.

O. Supplemental Guarantor Information

One of CrownRocks's wholly-owned subsidiaries, CrownRock Finance, is a co-issuer of the 2025 Senior Notes. Two of CrownRock's wholly-owned subsidiaries, Roddy and Canvasback, guarantee the 2025 Senior Notes. Such guarantees are joint and several, full and unconditional except for customary release provisions.

The Partnership has prepared Condensed Consolidating Financial Statements in order to quantify the assets, results of operations and cash flows of each of the Partnership's subsidiaries including the subsidiary co-issuer and guarantors. Abajo is shown in these Condensed Consolidating Financial Statements; however Abajo does not guarantee the Senior Notes.

The following Condensed Consolidating Balance Sheets at September 30, 2018 and December 31, 2017 and Condensed Consolidating Statements of Operations for the three and nine months ended September 30, 2018 and 2017 and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2018 and 2017, present financial information for CrownRock, L.P., on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiaries, including the subsidiary co-issuer (CrownRock Finance), subsidiary guarantors (Roddy and Canvasback) and the subsidiary non-guarantor (Abajo), on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Partnership on a consolidated basis.

O. Supplemental Guarantor Information (Continued)

	As of September 30, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Condensed Balance Sheet				(In thousands)			
Assets							
Cash and cash equivalents	$ 121,558	$ 997	$ -	$ 491	$ 126	$ -	$ 123,172
Accounts receivable – related party	77,034	255	-	-	(21)	(190)	77,078
Other current assets	1,255	99	-	-	28	-	1,382
Oil and natural gas properties	2,064,662	1,759	-	-	-	-	2,066,421
Other property and equipment	69,169	-	-	25,011	811	-	94,991
Deferred loan costs	1,786	-	-	-	-	-	1,786
Other assets	8,695	43	-	-	-	-	8,738
Investment in Abajo, LLC	385	-	-	-	-	(385)	-
Investment in Canvasback Properties, LLC	16,121	-	-	-	-	(16,121)	-
Investment in Roddy, LLC	2,137	-	-	-	-	(2,137)	-
Total Assets	**$ 2,362,802**	**$ 3,153**	**$ -**	**$ 25,502**	**$ 944**	**$ (18,833)**	**$ 2,373,568**
Liabilities and Partners' Capital							
Accounts payable & accrued liabilites - related party	$ 41,406	$ -	$ -	$ -	$ 192	$ (190)	$ 41,408
Accrued interest payable	30,736	-	-	-	-	-	30,736
Current portion of long-term debt	-	-	-	1,030	-	-	1,030
Other current liabilities	45,089	-	-	-	-	-	45,089
Long-term debt	1,168,497	-	-	8,351	-	-	1,176,848
Noncurrent derivative instruments	22,290	-	-	-	-	-	22,290
Asset retirement obligations	21,284	1,016	-	-	-	-	22,300
Total liabilities	**$ 1,329,302**	**$ 1,016**	**$ -**	**$ 9,381**	**$ 192**	**$ (190)**	**$ 1,339,701**
CrownRock, L.P. Partners' Capital	1,033,500	2,137	-	16,121	752	(19,010)	1,033,500
Non-controlling interest in subsidiary	-	-	-	-	-	367	367
Total Liabilities and Partners' Capital	**$ 2,362,802**	**$ 3,153**	**$ -**	**$ 25,502**	**$ 944**	**$ (18,833)**	**$ 2,373,568**

	As of December 31, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Condensed Balance Sheet				(In thousands)			
Assets							
Cash and cash equivalents	$ 94,873	$ 967	$ -	$ 90	$ 137	$ -	$ 96,067
Accounts receivable – related party	43,272	369	-	-	-	(190)	43,451
Other current assets	4,810	99	-	-	19	-	4,928
Derivative instruments	59,044	-	-	-	-	-	59,044
Oil and natural gas properties	1,653,361	1,815	-	-	-	-	1,655,176
Other property and equipment	67,469	-	-	24,985	955	-	93,409
Deferred loan costs	2,519	-	-	-	-	-	2,519
Other assets	6,224	43	-	-	-	-	6,267
Investment in Abajo, LLC	474	-	-	-	-	(474)	-
Investment in Canvasback Properties, LLC	14,956	-	-	-	-	(14,956)	-
Investment in Roddy, LLC	2,213	-	-	-	-	(2,213)	-
Total Assets	**$ 1,949,215**	**$ 3,293**	**$ -**	**$ 25,075**	**$ 1,111**	**$ (17,833)**	**$ 1,960,861**
Liabilities and Partners' Capital							
Accounts payable & accrued liabilites - related party	$ 7,037	$ 95	$ -	$ -	$ 182	$ (189)	$ 7,125
Accrued interest payable	12,500	-	-	-	-	-	12,500
Current portion of long-term debt	-	-	-	993	-	-	993
Other current liabilities	909	-	-	15	-	-	924
Long-term debt	987,895	-	-	9,110	-	-	997,005
Noncurrent derivative instruments	1,241	-	-	-	-	-	1,241
Asset retirement obligations	19,087	985	-	-	-	-	20,072
Other noncurrent liabilities	555	-	-	-	-	-	555
Total liabilities	**1,029,224**	**1,080**	**-**	**10,118**	**182**	**(189)**	**1,040,415**
CrownRock, L.P. Partners' Capital	919,991	2,213	-	14,957	929	(18,099)	919,991
Non-controlling interest in subsidiary	-	-	-	-	-	455	455
Total Liabilities and Partners' Capital	**$ 1,949,215**	**$ 3,293**	**$ -**	**$ 25,075**	**$ 1,111**	**$ (17,833)**	**$ 1,960,861**

O. Supplemental Guarantor Information (Continued)

	For the Three Months Ended September 30, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues:							
Oil and natural gas sales, rental income, transportation, SWD income, surface ownership and fresh water supply income	$ 205,162	$ 394	$ -	$ 590	$ 10	$ (590)	$ 205,566
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	38,162	363	-	-	5	-	38,530
Exploration costs	1,598	-	-	-	-	-	1,598
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	66,159	28	-	201	48	-	66,436
General and administrative	6,572	1	-	-	18	(590)	6,001
Operating income (loss)	92,671	2	-	389	(61)	-	93,001
Loss on derivatives not designated as hedges	(96,761)	-	-	-	-	-	(96,761)
Interest expense	(18,158)	-	-	(124)	-	-	(18,282)
Other income (expense)	1,164	-	-	-	-	(236)	928
Net income (loss)	(21,084)	2	-	265	(61)	(236)	(21,114)
Net loss attributable to non-controlling interest	-	-	-	-	-	30	30
Net income (loss) attributable to CrownRock, L.P.	$ (21,084)	$ 2	$ -	$ 265	$ (61)	$ (206)	$ (21,084)
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ (21,084)	$ 2	$ -	$ 265	$ (61)	$ (236)	$ (21,114)
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	30	30
Comprehensive income (loss) attributable to CrownRock, L.P.	$ (21,084)	$ 2	$ -	$ 265	$ (61)	$ (206)	$ (21,084)

	For the Three Months Ended September 30, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues:							
Oil and natural gas sales, rental income, transportation, SWD income and surface ownership income	$ 78,873	$ 319	$ -	$ 535	$ 12	$ (535)	$ 79,204
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	24,093	375	-	-	3	-	24,471
Exploration costs	2,625	-	-	-	-	-	2,625
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	36,455	31	-	182	48	-	36,716
General and administrative	5,280	1	-	-	19	(535)	4,765
Operating income (loss)	10,420	(88)	-	353	(58)	-	10,627
Gain on derivatives not designated as hedges	(14,441)	-	-	-	-	-	(14,441)
Loss on extinguishment of debt	(47)	-	-	-	-	-	(47)
Interest expense	(15,617)	-	-	(135)	-	-	(15,752)
Other income (expense)	(123)	(9)	-	-	-	(92)	(224)
Net income (loss)	(19,808)	(97)	-	218	(58)	(92)	(19,837)
Net loss attributable to non-controlling interest	-	-	-	-	-	29	29
Net income (loss) attributable to CrownRock, L.P.	$ (19,808)	$ (97)	$ -	$ 218	$ (58)	$ (63)	$ (19,808)
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ (19,808)	$ (97)	$ -	$ 218	$ (58)	$ (92)	$ (19,837)
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	29	29
Comprehensive income (loss) attributable to CrownRock, L.P.	$ (19,808)	$ (97)	$ -	$ 218	$ (58)	$ (63)	$ (19,808)

O. Supplemental Guarantor Information (Continued)

	For the Nine Months Ended September 30, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues:							
Oil and natural gas sales, rental income, transportation, SWD income, surface ownership and fresh water supply income	$ 496,087	$ 1,024	$ -	$ 1,748	$ 30	$ (1,748)	$ 497,141
Gain on sales and exchanges of oil and natural gas properties	63,253	-	-	-	-	-	63,253
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	96,323	1,011	-	-	10	-	97,344
Exploration costs	3,858	-	-	-	-	-	3,858
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	160,150	86	-	595	143	-	160,974
General and administrative	19,697	1	-	1	55	(1,748)	18,006
Operating income (loss)	279,312	(74)	-	1,152	(178)	-	280,212
Loss on derivatives not designated as hedges	(102,958)	-	-	-	-	-	(102,958)
Interest expense	(50,409)	-	-	(378)	-	-	(50,787)
Other income (expense)	1,957	-	-	40	-	(650)	1,347
Net income (loss)	127,902	(74)	-	814	(178)	(650)	127,814
Net loss attributable to non-controlling interest	-	-	-	-	-	88	88
Net income (loss) attributable to CrownRock, L.P.	$ 127,902	$ (74)	$ -	$ 814	$ (178)	$ (562)	$ 127,902
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 127,902	$ (74)	$ -	$ 814	$ (178)	$ (650)	$ 127,814
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	88	88
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 127,902	$ (74)	$ -	$ 814	$ (178)	$ (562)	$ 127,902

	For the Nine Months Ended September 30, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues:							
Oil and natural gas sales, rental income, transportation, SWD income and surface ownership income	$ 226,100	$ 956	$ -	$ 1,605	$ 44	$ (1,605)	$ 227,100
Gain on sales and exchanges of oil and natural gas properties	5,409	-	-	-	-	-	5,409
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	63,257	991	-	-	11	-	64,259
Exploration costs	10,210	-	-	-	-	-	10,210
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	106,737	88	-	543	143	-	107,511
General and administrative	16,554	1	-	-	56	(1,605)	15,006
Operating income (loss)	34,751	(124)	-	1,062	(166)	-	35,523
Gain on derivatives not designated as hedges	39,801	-	-	-	-	-	39,801
Loss on extinguishment of debt	(47)	-	-	-	-	-	(47)
Interest expense	(46,633)	-	-	(412)	-	-	(47,045)
Other income (expense)	144	(117)	-	-	-	(325)	(298)
Net income (loss)	28,016	(241)	-	650	(166)	(325)	27,934
Net loss attributable to non-controlling interest	-	-	-	-	-	82	82
Net income (loss) attributable to CrownRock, L.P.	$ 28,016	$ (241)	$ -	$ 650	$ (166)	$ (243)	$ 28,016
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 28,016	$ (241)	$ -	$ 650	$ (166)	$ (325)	$ 27,934
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	82	82
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 28,016	$ (241)	$ -	$ 650	$ (166)	$ (243)	$ 28,016

O. Supplemental Guarantor Information (Continued)

	For the Nine Months Ended September 30, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Condensed Statement of Cash Flows				(In thousands)			
Cash flows from operating activities	$ 343,733	$ 30	$ -	$ 1,427	$ (11)	$ -	$ 345,179
Cash flows from investing activities:							
Acquisition of leasehold and oil and natural gas properties	(11,091)	-	-	-	-	-	(11,091)
Capital expenditures on oil and natural gas properties	(467,886)	-	-	-	-	-	(467,886)
Additions to other property and equipment	(3,501)	-	-	(636)	-	-	(4,137)
Contributions to equity method investments	(1,782)	-	-	-	-	-	(1,782)
Investment in subsidiary	(350)	-	-	-	-	350	-
Total cash flows from investing activities	$ (484,610)	$ -	$ -	$ (636)	$ -	$ 350	$ (484,896)
Cash flows from financing activities:							
Capital contribution from parent	-	-	-	350	-	(350)	-
Distributions to partners	(11,297)	-	-	-	-	-	(11,297)
Proceeds from issuance of 5.625% Senior Notes due 2025	181,781	-	-	-	-	-	181,781
Repayments of long-term borrowings under construction loan	-	-	-	(740)	-	-	(740)
Proceeds from long-term borrowings under credit facility	55,000	-	-	-	-	-	55,000
Repayments of long-term borrowings under credit facility	(55,000)	-	-	-	-	-	(55,000)
Payments for loan and debt issue costs	(2,905)	-	-	-	-	-	(2,905)
Purchase of treasury units	(17)	-	-	-	-	-	(17)
Total cash flows from financing activities	$ 167,562	$ -	$ -	$ (390)	$ -	$ (350)	$ 166,822
Net increase (decrease) in cash and cash equivalents	$ 26,685	$ 30	$ -	$ 401	$ (11)	$ -	$ 27,105
Cash and cash equivalents, beginning of period	94,873	967	-	90	137	-	96,067
Cash and cash equivalents, end of period	$ 121,558	$ 997	$ -	$ 491	$ 126	$ -	$ 123,172

	For the Nine Months Ended September 30, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Condensed Statement of Cash Flows				(In thousands)			
Cash flows from operating activities	$ 194,502	$ (673)	$ -	$ 1,209	$ (4)	$ -	$ 195,034
Cash flows from investing activities:							
Acquisition of leasehold and oil and natural gas properties	(9,850)	-	-	-	-	-	(9,850)
Capital expenditures on oil and natural gas properties	(281,123)	90	-	-	-	-	(281,033)
Additions to other property and equipment	(32,039)	-	-	(828)	-	-	(32,867)
Proceeds from sale/exchange of oil and natural gas properties	7,332	-	-	-	-	-	7,332
Contributions to equity method investments	(2,060)	-	-	-	-	-	(2,060)
Investment in subsidiary	(400)	-	-	-	-	400	-
Total cash flows from investing activities	$ (318,140)	$ 90	$ -	$ (828)	$ -	$ 400	$ (318,478)
Cash flows from financing activities:							
Capital contribution from parent	-	-	-	400	-	(400)	-
Repayments from long-term borrowings under construction loan	-	-	-	(705)	-	-	(705)
Proceeds from long-term borrowings under credit facility	60,000	-	-	-	-	-	60,000
Payments for loan costs	(161)	-	-	-	-	-	(161)
Purchase of treasury units	(4,920)	-	-	-	-	-	(4,920)
Total cash flows from financing activities	$ 54,919	$ -	$ -	$ (305)	$ -	$ (400)	$ 54,214
Net increase (decrease) in cash and cash equivalents	$ (68,719)	$ (583)	$ -	$ 76	$ (4)	$ -	$ (69,230)
Cash and cash equivalents, beginning of period	121,965	1,591	-	50	173	-	123,779
Cash and cash equivalents, end of period	$ 53,246	$ 1,008	$ -	$ 126	$ 169	$ -	$ 54,549

P. Subsequent Events

New commodity derivative contracts. After September 30, 2018 and through November 9, 2018, the Partnership entered into the following oil price commodity derivative contracts to hedge an additional portion of its estimated future oil production:

	Aggregate Volume	Price Per Bbl	Contract Period
Oil (volumes in Bbls):			
Price swap (a)	637,000	$ 69.65	1/1/20 - 3/31/20
	728,000	$ 68.77	4/1/20 - 6/30/20
	736,000	$ 67.65	7/1/20 - 9/30/20
	552,000	$ 66.99	10/1/20 - 12/31/20

(a) The index prices for the oil price swaps are based on the NYMEX - West Texas Intermediate monthly average futures price.

Commodity derivative contracts at November 9, 2018. The following table sets forth the Partnership's outstanding commodity derivative contracts, by quarter of settlement, at November 9, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2018:					
Volume (Bbl)				2,162,000	2,162,000
Price per Bbl				$ 67.81	$ 67.81
2019:					
Volume (Bbl)	2,178,000	2,275,000	2,944,000	2,944,000	10,341,000
Price per Bbl	$ 60.94	$ 62.34	$ 62.26	$ 62.52	$ 62.07
2020:					
Volume (Bbl)	2,093,000	1,274,000	736,000	552,000	4,655,000
Price per Bbl	$ 67.26	$ 67.58	$ 67.65	$ 66.99	$ 67.37
Oil Basis Swaps: (b)					
2018:					
Volume (Bbl)				1,610,000	1,610,000
Price per Bbl				$ (8.82)	$ (8.82)
2019:					
Volume (Bbl)	1,890,000	2,275,000	2,944,000	2,944,000	10,053,000
Price per Bbl	$ (0.35)	$ (0.35)	$ (1.00)	$ (1.00)	$ (0.73)
2020:					
Volume (Bbl)	2,275,000	2,275,000	2,760,000	2,760,000	10,070,000
Price per Bbl	$ (0.62)	$ (0.62)	$ (0.67)	$ (0.67)	$ (0.65)

(a) The index prices for the oil price swaps are based on the NYMEX - West Texas Intermediate monthly average futures price.
(b) The basis differential price is between Midland - WTI and Cushing - WTI.

* * * * * * * * * * * * * * * * * * * *

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with consolidated financial statements and related notes included elsewhere in this report and with our financial statements in our annual report for the year ended December 31, 2017. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Information," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are an independent oil and natural gas partnership engaged in the acquisition, development and exploration of oil and natural gas properties. Our assets are located in Texas, New Mexico and Utah, and our operations are primarily focused on the development of our core Permian Basin assets. We intend to grow our reserves and production through development drilling and exploration activities on our multi-year project inventory and through acquisitions or exchanges that meet our strategic and financial objectives.

Our core properties are in the Northern Midland Basin in the Permian Basin of West Texas where we intend to focus primarily on drilling horizontal targets on multiple benches. The Permian Basin of West Texas is characterized by an extensive production history, predominantly oil-focused drilling targets, abundant infrastructure, wells with long reserve lives and multiple production horizons. The Wolfberry play is a modification and extension of the Spraberry play, while the Wolfcamp and Spraberry shale play utilizes horizontal drilling in the historic Spraberry play, the majority of which is designated in the Spraberry Trend Area Field. According to the latest information available from the Energy Information Administration of the U.S. Department of Energy, the Spraberry Trend Area ranks as the second largest oilfield in the United States by proved reserves and by estimated oil production. Based on the returns we have generated through our drilling efforts to date, the number of undrilled locations in our drilling plan, and our observation of the activity and results of other operators in this area, we believe the Midland Basin represents one of the premier oil and gas development opportunities in North America. From October 2007 through December 2014, we primarily focused on drilling vertical wells in the Midland Basin. In January 2015, we initiated our horizontal program, with our first horizontal well coming on line in March 2015. We spent much of 2016 preparing to accelerate our horizontal activity. This included identifying potential horizontal drilling locations plus identifying optimum spacing between wells, including interval spacing between zones or benches. During 2017, we increased horizontal drilling, and drilled approximately 60% more horizontal wells as compared to 2016. We continued to engineer our optimal spacing development program, which resulted in a build-up of an inventory of drilled but uncompleted wells in order to concurrently complete wells in each spacing unit block.

We have a large inventory of horizontal drilling opportunities. This inventory is evolving as a result of several factors, including additional geological information obtained and acreage changes resulting from property exchanges. As of September 30, 2018, on our Midland Basin acreage, we have identified 2,819 net Tier 1 and 1,359 net Tier 2 horizontal locations that can be drilled wholly or partially on our acreage based primarily on current industry practice of 660-foot interwell spacing with some 880-foot or 1,320-foot spacing in certain areas and benches. Since initiating our horizontal program in January 2015, through September 30, 2018, we have drilled 130 net horizontal locations. We count inventory well locations within benches in the Midland Basin that we believe will be prospective based on success of offset operators, or vertical well experience in drilling through and producing from these benches, and our analysis of available engineering and geological data both within and by the boundaries of our leases. Of the 2,819 net Tier 1 horizontal locations, 2,327 are fully controlled on our acreage in 1.5-mile or 2-mile laterals, and 492 are possible when pooled with offset operators to create 1.5-mile laterals on co-owned acreage. Of the 2,327 fully controlled Tier 1 locations, 367 are included as proved undeveloped ("PUD") locations in our latest reserve report dated October 1, 2018. We define a Tier 1 location as having an existing economic horizontal well or wells on or proximal to our acreage. Tier 2 locations have similar geologic parameters as Tier 1 locations, but lack existing offset production required to be considered at Tier 1.

Our other properties are located in different parts of the Permian Basin of West Texas and New Mexico, in Mitchell County on the Permian Basin's Eastern Shelf and in Andrews and Gaines Counties on the Permian Basin's Central Basin Platform, as well as acreage in the San Juan Basin of New Mexico and the Paradox Basin of Utah.

Financial and Operating Performance

Our financial and operating performance for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017 included the following highlights:

- Net income attributable to the Partnership increased by $99.9 million to net income of $127.9 million for the first nine months in 2018, as compared to net income of $28.0 million for the first nine months in 2017. The increase in earnings is primarily due to:
    - a $255.4 million increase in oil and natural gas revenues as a result of a 34% increase in commodity prices (oil equivalent, excluding derivatives) and a 60% increase in production (oil equivalent);
    - $63.3 million of non-cash gains on exchanges of oil and natural gas properties during the first nine months of 2018 as compared to $5.4 million of cash and non-cash gains on sales and exchanges of oil and natural gas properties during 2017;
    - $3.9 million in exploration costs during 2018, as compared to $10.2 million during 2017;
    - $2.2 million in impairment expense during 2018, as compared to $4.5 million during 2017;
    - a $14.6 million increase in other revenue during the first nine months of 2018 as compared to the first nine months in 2017;
    - offset by:
        - a $33.0 million increase in oil and natural gas production costs in 2018 due to increases in lease operating expenses and production taxes;
        - a $55.7 million increase in depreciation, depletion and amortization due to increased capitalized costs associated with the new wells that were successfully drilled and completed in 2017 and 2018;
        - a $103.0 million loss on derivatives during the first nine months in 2018, comprised of $21.4 million gain on cash settlements offset by a $124.4 million mark-to-market loss primarily the result of increases in forward looking crude oil prices, as compared to a $39.8 million gain in the first nine months in 2017, comprised of $91.8 million gain on cash settlements offset by a $52.0 million mark-to-market loss; and
        - a $3.7 million increase in interest expense during 2018 due to an increase in the outstanding debt balance as compared to 2017.
- Average daily sales volumes increased during the first nine months of 2018 by 60% from 24,777 Boe per day during the first nine months in 2017 to 39,647 Boe per day during the first nine months in 2018.
- Net cash provided by operating activities increased by $150.2 million to $345.2 million for the first nine months in 2018, as compared to $195.0 million for the first nine months in 2017, principally

due to increases in oil and natural gas revenues, offset by increases in production costs, decreases in working capital items and decreases in cash settlements on crude oil derivatives.

- At September 30, 2018, we had no amounts outstanding and our availability under our credit facility was $500 million.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, natural gas and natural gas liquids, (ii) market uncertainty and (iii) a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids, include, but are not limited to:

- the level of consumer demand, domestic and worldwide, for oil, NGL and natural gas;
- the domestic and worldwide supply of oil, NGL and natural gas;
- inventory levels at Cushing, Oklahoma, the benchmark for WTI oil prices;
- natural gas inventory levels in the United States;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and quantity of foreign imports of oil, NGL and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and other state-controlled oil companies to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxation;
- the price, availability and acceptance of alternative fuel sources;
- the effect of energy conservation efforts;
- weather conditions;
- the effect of oil and LNG imports to and exports from the United States;
- political conditions or hostilities in oil, NGL and natural gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption and energy supply;
- variations between product prices at sales points and applicable index prices; and
- worldwide economic conditions.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes H and P of the Notes to Condensed Consolidated Financial Statements for additional information regarding our commodity derivative positions as of September 30, 2018 and additional derivative contracts entered into subsequent to September 30, 2018, respectively.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil price was higher and the average natural gas price was lower during the comparable periods of 2018 measured against 2017, respectively. The following table sets forth the average New York Mercantile Exchange ("NYMEX") oil and natural gas prices for the three and nine months ended September 30, 2018 and 2017, as well as the high and low NYMEX prices for the same periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Average NYMEX prices:				
Oil (Bbl)	$ 69.51	$ 48.17	$ 66.77	$ 49.42
Natural gas (MMBtu)	$ 2.87	$ 2.95	$ 2.85	$ 3.06
High and Low NYMEX prices:				
Oil (Bbl):				
High	$ 74.14	$ 52.22	$ 74.15	$ 54.45
Low	$ 65.01	$ 44.23	$ 59.19	$ 42.53
Natural gas (MMBtu):				
High	$ 3.08	$ 3.15	$ 3.63	$ 3.72
Low	$ 2.72	$ 2.77	$ 2.55	$ 2.56

Recent Events

Midland WTI – Cushing WTI basis differential increase. During the nine months ended September 30, 2018, we have experienced a decrease in our realized oil price, excluding derivatives, compared to the average NYMEX market price. This is a result of the increase in the Midland – Cushing differential deduction, a component of the pricing formula in all our crude oil sales contracts. This basis differential (referred to as the "Mid-Cush differential") between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil has increased due to the production of oil in the Midland Basin reaching a point that it temporarily surpasses the available transportation and refining capacity in the area. Although we have hedged the Mid – Cush differential for a portion of our estimated oil production through December 2020, our results of operations and financial condition could be negatively affected if commodity basis differentials versus NYMEX continue to negatively increase. The following table sets forth the (1) average NYMEX oil prices, (2) realized oil prices, the differential between (1) and (2), and effect of the cash receipts from crude oil basis derivatives for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Realized oil price, excluding derivatives	$ 56.40	$ 48.05	$ 59.55	$ 47.84
Avg. NYMEX futures price	$ 69.51	$ 48.17	$ 66.77	$ 49.42
Basis differential, incl. transportation	$ (13.11)	$ (0.12)	$ (7.22)	$ (1.58)
Basis derivative effect (cash settlements received)	$ 2.47	$ -	$ 2.06	$ -
Net basis differential, including derivatives	$ (10.64)	$ (0.12)	$ (5.16)	$ (1.58)

The increase in the basis differential for the three months ended September 30, 2018 as compared to 2017 of $12.99 per barrel excluding derivatives reduced crude oil revenue by approximately $39.0 million based on crude oil production for the three months ended September 30, 2018.

Exchanges. If it is deemed value-adding, we will enter into exchange agreements with third parties to exchange proved and unproved oil and natural gas properties as part of our strategy to consistently pursue financially viable deals to further block up our acreage and thereby enhance our horizontal well drilling inventory in the Permian Basin. We completed multiple exchange transactions during the nine months ended September 30, 2018. The significant transactions are shown below.

On August 22, 2018, we exchanged approximately 2,184 gross (1,849 net) acres of undeveloped leasehold acreage in Glasscock, Martin, and Midland counties, Texas to a third party in exchange for 842 gross (806 net) acres of undeveloped leasehold acreage in Glasscock, Howard, Martin, and Midland counties, Texas. The exchange blocked up our acreage position and thereby enhanced our horizontal well inventory in the Midland Basin. The transaction included the exchange of both proved and unproved oil and natural gas properties. No gain or loss was recognized.

On May 15, 2018, we exchanged approximately 576 gross (221 net) acres of undeveloped leasehold acreage in Midland and Reagan counties, Texas and $0.5 million in cash to a third party in exchange for 1,025 gross (221 net) acres of developed and undeveloped leasehold acreage and working interests in 6 gross (3.6 net) PDP vertical wells in Martin and Howard counties, Texas. The exchange increased our working interest in existing CrownQuest-operated wells and blocked up our acreage position and thereby enhanced our horizontal drilling inventory in the Midland Basin. The transaction included the exchange of both proved and unproved oil and natural gas properties. No gain or loss was recognized.

On May 14, 2018, we exchanged approximately 668 gross (539 net) acres of developed and undeveloped leasehold acreage and working interests in 2 gross (2 net) PDP vertical wells located in Howard, Martin, Dawson, and Borden counties, Texas to a third party in exchange for 564 (460 net) acres of undeveloped leasehold acreage located in Howard County, Texas. The exchange blocked up our acreage position and thereby enhanced our horizontal well inventory in the Midland Basin. This transaction included the exchange of both proved and unproved oil and natural gas properties and was accounted for at fair value and, as a result, we recorded a non-cash gain of $16.1 million.

On May 1, 2018, we exchanged 2,156 gross (1,458 net) acres of developed and undeveloped leasehold acreage and working interests in 1 gross (.5 net) PDP vertical well and 1 gross (.7 net) proved non-producing vertical well located in Midland and Martin counties, Texas to a third party in exchange for 3,274 gross (1,377 net) acres of undeveloped leasehold acreage located in Martin, Howard, Glasscock, and Midland counties, Texas. The exchange blocked up our acreage position and thereby enhanced our horizontal well inventory in the Midland Basin. This transaction included the exchange of both proved and unproved oil and natural gas properties and was accounted for at fair value and, as a result, we recorded a non-cash gain of $47.1 million.

5.625% Senior Notes due 2025. On May 22, 2018, we issued an additional $185 million aggregate principal amount of 2025 Senior Notes at 98.26% of par. These notes were fungible with the original notes issued in October 2017 and are governed by the same indenture and thus contain the same terms and conditions of the original notes. We issued the additional 2025 Senior Notes to pay off advances on our Credit Facility and for general partnership purposes, including the funding of a portion of our capital development plan.

Derivative Financial Instruments

Derivative financial instrument exposure. At September 30, 2018, the fair value of our financial derivatives was a net liability of $66.5 million. All of our counterparties to these financial derivatives are a party to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable.

Selected Oil and Natural Gas Information

Productive wells. The following table sets forth information at September 30, 2018 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian Basin	896	128	1,024	692.5	93.1	785.6
San Juan Basin	7	54	61	7.0	34.6	41.6
Paradox Basin	-	2	2	-	1.2	1.2
Total	903	184	1,087	699.5	128.9	828.4

The following table sets forth the number of productive oil and natural gas wells attributable to our properties as of December 31, 2017.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian Basin	792	120	912	599.4	88.9	688.3
San Juan Basin	6	50	56	6.0	32.3	38.3
Paradox Basin	-	2	2	-	1.2	1.2
Total	798	172	970	605.4	122.4	727.8

Results of Operations

The following table sets forth production and operating data for the three and nine months ended September 30, 2018 and 2017.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Net production volumes:				
Oil (Bbl)	2,998,705	1,320,696	6,980,952	3,808,857
Natural gas (Mcf)	3,578,739	2,569,081	9,043,439	7,198,854
Natural gas liquids (Bbl)	995,892	665,622	2,335,391	1,755,531
Oil equivalent (Boe)	4,591,054	2,414,498	10,823,583	6,764,197
Average daily production volumes:				
Oil (Bbl)	32,595	14,355	25,571	13,952
Natural gas (Mcf)	38,899	27,925	33,126	26,369
Natural gas liquids (Bbl)	10,825	7,235	8,555	6,431
Oil equivalent (Boe)	49,903	26,245	39,647	24,777
Average prices:				
Oil, without derivatives ($/Bbl)	$ 56.40	$ 48.05	$ 59.55	$ 47.84
Oil, with derivatives ($/Bbl) (a)	$ 58.39	$ 72.87	$ 62.62	$ 71.96
Natural gas, without derivatives ($/Mcf)	$ 1.40	$ 2.08	$ 1.42	$ 2.10
Natural gas liquids, without derivatives ($/Bbl)	$ 24.55	$ 13.07	$ 21.35	$ 14.66
Oil equivalent, without derivatives ($/Boe)	$ 43.26	$ 32.09	$ 44.21	$ 32.98
Oil equivalent, with derivatives ($/Boe) (a)	$ 44.56	$ 45.67	$ 46.18	$ 46.56
Operating costs and expenses per Boe:				
Lease operating expenses and workover costs	$ 5.85	$ 7.89	$ 6.45	$ 7.18
Oil and natural gas production and ad valorem taxes	$ 2.54	$ 2.25	$ 2.54	$ 2.32
Depreciation, depletion and amortization	$ 14.25	$ 14.77	$ 14.61	$ 15.13
General and administrative	$ 1.31	$ 1.97	$ 1.66	$ 2.22

(a) Includes the effect of the cash receipts from commodity derivatives not designated as hedges and reported in other income and expenses. The following table reflects the amounts of cash settlements received from commodity derivatives not designated as hedges that were included in computing average prices with hedges.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Cash receipts from derivatives not designated as hedges:				
Oil and oil basis derivatives	$ 5,951	$ 32,776	$ 21,390	$ 91,877

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash payments on/receipts from commodity derivatives that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

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

Oil and natural gas revenues.

	Three Months Ended September 30,	
	2018	2017
	(In thousands)	
Oil sales	$ 169,138	$ 63,458
Natural gas sales	5,024	5,335
Natural gas liquids sales	24,449	8,698
Total oil and natural gas sales	$ 198,611	$ 77,491

Revenue from oil and natural gas operations was $198.6 million for the three months ended September 30, 2018, an increase of $121.1 million (156%) from $77.5 million for the three months ended September 30, 2017. This increase was primarily due to a 35% increase in oil, natural gas and natural gas liquids prices (oil equivalent excluding the effects of derivative activities) during 2018 as compared to 2017 and a 90% increase in production (oil equivalent) as a result of increased drilling and completion activity during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. Specifics include the following:

- the average realized oil price (excluding the effects of derivative activities) was $56.40 per Bbl during the three months ended September 30, 2018, an increase of 17% from $48.05 per Bbl during the three months ended September 30, 2017;
- total oil production was 2,998,705 Bbl for the three months ended September 30, 2018, an increase of 1,678,009 Bbl (127%) from 1,320,696 Bbl for the three months ended September 30, 2017;
- the average realized natural gas price (excluding the effects of derivative activities) was $1.40 per Mcf during the three months ended September 30, 2018, a decrease of 33% from $2.08 per Mcf during the three months ended September 30, 2017;
- total natural gas production was 3,578,739 Mcf for the three months ended September 30, 2018, an increase of 1,009,658 Mcf (39%) from 2,569,081 Mcf for the three months ended September 30, 2017;
- the average realized natural gas liquids price (excluding the effects of derivative activities) was $24.55 per Bbl during the three months ended September 30, 2018, an increase 88% from $13.07 per Bbl during the three months ended September 30, 2017; and
- total natural gas liquids production was 995,892 Bbl for the three months ended September 30, 2018, an increase of 330,270 Bbl (50%) from 665,622 Bbl for the three months ended September 30, 2017.

Production expenses. The following table provides the components of our total oil and natural gas production expenses for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 26,851	$ 5.85	$ 19,048	$ 7.89
Production and ad valorem taxes	11,679	2.54	5,423	2.25
Total oil and natural gas production expenses	$ 38,530	$ 8.39	$ 24,471	$ 10.14

Among the cost components of production expenses, in general, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses. Lease operating expenses were $26.9 million ($5.85 per Boe) for the three months ended September 30, 2018 which was an increase of $7.9 million (42%) from $19.0 million ($7.89 per Boe) for the three months ended September 30, 2017. The increase in lease operating expenses was due to the increase in the number of wells being placed in service as a result of successful drilling efforts during 2018 and 2017, offset by a slight decrease in well servicing costs on downhole and surface equipment. On a per Boe basis, these servicing costs decreased 55% which approximated $3.4 million ($0.75 per Boe) for the three months ended September 30, 2018 as compared to approximately $4.0 million ($1.67 per Boe) for the three months ended September 30, 2017.

The 26% decrease in lease operating expenses per Boe was primarily due to the 90% increase in production (oil equivalent), offset by the factors listed above. The increase in production was a result of successful drilling efforts during 2018 and 2017 from our active Midland Basin horizontal drilling program. This resulted in higher per well production rates in 2018 as compared to 2017.

Production and ad valorem taxes. The Partnership recorded production and ad valorem taxes of $11.7 million for the three months ended September 30, 2018, as compared to $5.4 million for the three months ended September 30, 2017. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, ad valorem taxes are based upon prior year commodity prices; whereas production taxes are based upon current year commodity prices.

The following table provides the Partnership's production and ad valorem taxes per BOE for the three months ended September 30, 2018 and 2017.

	Three Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 9,933	$ 2.16	$ 3,923	$ 1.63
Ad Valorem taxes	1,746	0.38	1,500	0.62
Total production and ad valorem taxes	$ 11,679	$ 2.54	$ 5,423	$ 2.25

Production taxes per unit of production were $2.16 per Boe for the three months ended September 30, 2018, an increase of 33% from $1.63 per Boe for the three months ended September 30, 2017. The oil revenue/gas revenue components of total revenue from oil and natural gas operations in 2018 were 85%/15% as compared to 2017 at 82%/18%. Production taxes, as a percentage of oil and natural gas revenues, were consistent at approximately 5% for the quarters ended September 30, 2018 and 2017. Over the same period, our per Boe commodity prices (excluding the effects of derivatives) increased 35%.

Exploration costs. Exploration costs were $1.6 million for the three months ended September 30, 2018. This 2018 amount was primarily comprised of $0.8 million of dry hole expense of one oil and natural gas well on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas and $0.7 million of leasehold costs of certain leases in the Permian Basin of Texas which the Partnership allowed to expire as they were determined to have no future development potential. Exploration costs were $2.6 million for the three months ended September 30, 2017. This 2017 amount was primarily comprised of leasehold costs of certain leases in the Permian Basin of Texas which the Partnership allowed to expire as they were determined to have no future development potential.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 64,310	$ 14.01	$ 34,977	$ 14.48
Depletion and depreciation of other property and equipment	1,108	0.24	691	0.29
Total depletion, depreciation and amortization	$ 65,418	$ 14.25	$ 35,668	$ 14.77
Average oil price used to estimate proved oil reserves at period end	$ 59.90		$ 46.27	
Average natural gas price used to estimate proved natural gas reserves at period end	$ 2.91		$ 3.00	

Depletion of proved oil and natural gas properties was $64.3 million ($14.01 per Boe) for the three months ended September 30, 2018, an increase of $29.3 million (84%) from $35.0 million ($14.48 per Boe) for the three months ended September 30, 2017. The increase in depletion expense was primarily due to the increases in production and the increase in capitalized costs being depleted and depreciated resulting from the successful 2017 and 2018 drilling programs including the reclassification of unproved leasehold costs to proved leasehold costs as additional proved reserves are added offset by increases in proved developed producing reserves and total proved reserves. The increase in reserves is primarily due to the results of our successful horizontal well development in 2017 and 2018.

The 3% decrease in depletion expense per Boe was primarily due to the increase in proved developed producing reserves and total proved reserves of 44% and 34%, respectively, at September 30, 2018 as compared to September 30, 2017 and the increase in production from period to period.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 4,643	$ 1.02	$ 3,354	$ 1.39
Non-cash unit-based compensation	1,253	0.27	1,038	0.43
Other non-cash expenses	105	0.02	373	0.15
Total general and administrative expenses	$ 6,001	$ 1.31	$ 4,765	$ 1.97

General and administrative expenses were approximately $6.0 million ($1.31 per Boe) for the three months ended September 30, 2018, an increase of $1.2 million (26%) from $4.8 million ($1.97 per Boe) for the three months ended September 30, 2017. The increase in general and administrative expenses is due to increases in CrownQuest's staffing and non-cash unit-based compensation expenses resulting from the continued growth of the Partnership. The 34% decrease in general and administrative expenses per Boe was primarily due to the increase in production from period to period offset by the factors listed above.

Net gains (losses) on derivatives. The following table sets forth the cash settlements and the non-cash mark-to-market adjustments for our derivative contracts for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,	
(in thousands)	**2018**	**2017**
Cash receipts:		
Commodity derivatives - oil	$ 5,951	$ 32,776
Mark-to-market loss:		
Commodity derivatives - oil	(102,712)	(47,217)
Realized and unrealized net loss on derivatives	$ (96,761)	$ (14,441)

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the three months ended September 30, 2018 and 2017:

	Three Months Ended September 30,	
($ in thousands)	**2018**	**2017**
Interest expense	$ 18,282	$ 15,752
Weighted average interest rate	6.12%	8.11%
Weighted average cash interest rate	5.83%	7.65%
Weighted average debt balance	$ 1,194,642	$ 776,706

The increase in weighted average debt balance during the three months ended September 30, 2018 was due to the issuance of 2025 Senior Notes in October 2017 and May 2018. The increase in interest expense is due to an increase in the weighted average debt balance between periods. The decrease in the weighted average interest rate and the weighted average cash interest rate during the three months ended September 30, 2018 is due the lower weighted average interest rate on the 2025 Senior Notes of 5.67% as compared to the weighted average interest rate on the 2021 Senior Notes and the 2023 Senior Notes of 7.53%.

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

Oil and natural gas revenues.

	Nine Months Ended September 30,	
	2018	**2017**
	(In thousands)	
Oil sales	$ 415,731	$ 182,219
Natural gas sales	12,875	15,117
Natural gas liquids sales	49,863	25,732
Total oil and natural gas sales	$ 478,469	$ 223,068

Revenue from oil and natural gas operations was $478.5 million for the nine months ended September 30, 2018, an increase of $255.4 million (114%) from $223.1 million for the nine months ended September 30, 2017. This increase was primarily due to a 34% increase in oil, natural gas and natural gas liquids prices (oil equivalent excluding the effects of derivative activities) during 2018 as compared to 2017 and a 60% increase in production (oil equivalent) as a result of increased drilling and completion activity during the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. Specifics include the following:

- the average realized oil price (excluding the effects of derivative activities) was $59.55 per Bbl during the nine months ended September 30, 2018, an increase of 24% from $47.84 per Bbl during the nine months ended September 30, 2017;
- total oil production was 6,980,952 Bbl for the nine months ended September 30, 2018, an increase of 3,172,095 Bbl (83%) from 3,808,857 Bbl for the nine months ended September 30, 2017;
- the average realized natural gas price (excluding the effects of derivative activities) was $1.42 per Mcf during the nine months ended September 30, 2018, a decrease of 32% from $2.10 per Mcf during the nine months ended September 30, 2017;
- total natural gas production was 9,043,439 Mcf for the nine months ended September 30, 2018, an increase of 1,844,585 Mcf (26%) from 7,198,854 Mcf for the nine months ended September 30, 2017;
- the average realized natural gas liquids price (excluding the effects of derivative activities) was $21.35 per Bbl during the nine months ended September 30, 2018, an increase 46% from $14.66 per Bbl during the nine months ended September 30, 2017; and
- total natural gas liquids production was 2,335,391 Bbl for the nine months ended September 30, 2018, an increase of 579,860 Bbl (33%) from 1,755,531 Bbl for the nine months ended September 30, 2017.

Production expenses. The following table provides the components of our total oil and natural gas production expenses for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 69,815	$ 6.45	$ 48,545	$ 7.18
Production and ad valorem taxes	27,529	2.54	15,714	2.32
Total oil and natural gas production expenses	$ 97,344	$ 8.99	$ 64,259	$ 9.50

Among the cost components of production expenses, in general, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses. Lease operating expenses were $69.8 million ($6.45 per Boe) for the nine months ended September 30, 2018 which was an increase of $21.3 million (44%) from $48.5 million ($7.18 per Boe) for the nine months ended September 30, 2017. The increase in lease operating expenses was due to the increase in the number of wells being placed in service as a result of successful drilling efforts during 2018 and 2017 including an increase in well servicing costs on downhole and surface equipment. On a per Boe basis, these servicing costs decreased 18% which approximated $11.0 million ($1.02 per Boe) for the nine months ended September 30, 2018 as compared to approximately $8.4 million ($1.24 per Boe) for the nine months ended September 30, 2017.

The 10% decrease in lease operating expenses per Boe was primarily due to the 60% increase in production (oil equivalent), offset by the factors listed above. The increase in production was a result of successful drilling efforts during 2018 and 2017 from our active Midland Basin horizontal drilling program. This resulted in higher per well production rates in 2018 as compared to 2017.

Production and ad valorem taxes. The Partnership recorded production and ad valorem taxes of $27.5 million for the nine months ended September 30, 2018, as compared to $15.7 million for the nine months ended September 30, 2017. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, ad valorem taxes are based upon prior year commodity prices; whereas production taxes are based upon current year commodity prices.

The following table provides the Partnership's production and ad valorem taxes per BOE for the nine months ended September 30, 2018 and 2017.

	Nine Month Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Production taxes	$ 23,490	$ 2.17	$ 11,444	$ 1.69
Ad Valorem taxes	4,039	0.37	4,270	0.63
Total production and ad valorem taxes	$ 27,529	$ 2.54	$ 15,714	$ 2.32

Production taxes per unit of production were $2.17 per Boe for the nine months ended September 30, 2018, an increase of 28% from $1.69 per Boe for the nine months ended September 30, 2017. The oil revenue/gas revenue components of total revenue from oil and natural gas operations in 2018 were 87%/13% as compared to 2017 at 82%/18%. Production taxes, as a percentage of oil and natural gas revenues, were consistent at approximately 5% for the nine months ended September 30, 2018 and 2017. Over the same period, our per Boe commodity prices (excluding the effects of derivatives) increased 34%.

Exploration costs. Exploration costs were $3.9 million for the nine months ended September 30, 2018. This 2018 amount was primarily comprised of $3.0 million of dry hole expense of three oil and natural gas wells on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas and $0.7 million of leasehold costs of certain leases in the Permian Basin of Texas which the Partnership allowed to expire as they were determined to have no future development potential. Exploration costs were $10.2 million for the nine months ended September 30, 2017. This 2017 amount was primarily comprised of leasehold costs of certain leases in the Permian Basin of Texas which the Partnership allowed to expire as they were determined to have no future development potential.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 155,557	$ 14.38	$ 100,312	$ 14.83
Depletion and depreciation of other property and equipment	2,540	0.23	2,054	0.30
Total depletion, depreciation and amortization	$ 158,097	$ 14.61	$ 102,366	$ 15.13
Average oil price used to estimate proved oil reserves at period end	$ 59.90		$ 46.27	
Average natural gas price used to estimate proved natural gas reserves at period end	$ 2.91		$ 3.00	

Depletion of proved oil and natural gas properties was $155.6 million ($14.38 per Boe) for the nine months ended September 30, 2018, an increase of $55.3 million (55%) from $100.3 million ($14.83 per Boe) for the nine months ended September 30, 2017. The increase in depletion expense was primarily due to the increases in production and the increase in capitalized costs being depleted and depreciated resulting from the successful 2017 and 2018 drilling programs including the reclassification of unproved leasehold costs to proved leasehold costs as additional proved reserves are added offset by increases in proved developed producing reserves and total proved reserves. The increase in reserves is primarily due to the results of our successful horizontal well development in 2017 and 2018.

The 3% decrease in depletion expense per Boe was primarily due to the increase in proved developed producing reserves and total proved reserves of 44% and 34%, respectively, at September 30, 2018 as compared to September 30, 2017 and the increase in production from period to period.

General and administrative expenses. The following table provides components of our general and administrative expenses for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,			
	2018		2017	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses	$ 13,603	$ 1.25	$ 10,829	$ 1.61
Non-cash unit-based compensation	3,452	0.32	3,069	0.45
Other non-cash expenses	951	0.09	1,108	0.16
Total general and administrative expenses	$ 18,006	$ 1.66	$ 15,006	$ 2.22

General and administrative expenses were approximately $18.0 million ($1.66 per Boe) for the nine months ended September 30, 2018, an increase of $3.0 million (20%) from $15.0 million ($2.22 per Boe) for the nine months ended September 30, 2017. The increase in general and administrative expenses is due to increases in CrownQuest's staffing and non-cash unit-based compensation expenses resulting from the continued growth of the Partnership. The 25% decrease in general and administrative expenses per Boe was primarily due to the increase in production from period to period offset by the factors listed above.

Net gains (losses) on derivatives. The following table sets forth the cash settlements and the non-cash mark-to-market adjustments for our derivative contracts for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,	
(in thousands)	2018	2017
Cash receipts:		
Commodity derivatives - oil	$ 21,390	$ 91,877
Mark-to-market loss:		
Commodity derivatives - oil	(124,348)	(52,076)
Realized and unrealized net gain (loss) on derivatives	$ (102,958)	$ 39,801

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,	
($ in thousands)	2018	2017
Interest expense	$ 50,787	$ 47,045
Weighted average interest rate	6.10%	8.15%
Weighted average cash interest rate	5.82%	7.69%
Weighted average debt balance	$ 1,110,327	$ 769,589

The increase in weighted average debt balance during the nine months ended September 30, 2018 was due to the issuance of 2025 Senior Notes in October 2017 and May 2018. The increase in interest expense is due to an increase in the weighted average debt balance between periods. The decrease in the weighted average interest rate and the weighted average cash interest rate during the nine months ended September 30, 2018 is due to the lower weighted average interest rate on the 2025 Senior Notes of 5.67% as compared to the weighted average interest rate on the 2021 Senior Notes and the 2023 Senior Notes of 7.53%.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are for the development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations, distributions to Holdings and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility and proceeds from the disposition of assets or alternative financing sources, as discussed in "Capital resources" below.

Oil and natural gas properties. Our cash flows used by investing activities in our oil and natural gas properties during the nine months ended September 30, 2018 and 2017 totaled $479.0 million and $290.9 million, respectively. Of these amounts, $11.1 million and $9.9 million, respectively, were used in the acquisition of proved oil and natural gas properties and undeveloped leasehold acreage in West Texas and $467.9 million and $281.0 million, respectively, were used in drilling and development. The 2018 expenditures were funded by cash flow from operations, borrowings under our credit facility and proceeds from the issuance of the 2025 Senior Notes in October 2017 and May 2018. The 2017 expenditures were funded by cash flow from operations, cash on hand and borrowings under our credit facility.

Our capital expenditure plan for drilling and completion activities for 2018 will range from approximately $573 million to $630 million, all of which has been allocated to drilling activities in the Permian Basin. Our capital expenditure plan does not include acquisitions, outside operated projects or asset retirement obligations. In addition to our drilling and completion capital expenditures, our 2018 capital expenditure plan includes approximately $55 million for infrastructure (such as tank batteries, gathering pipelines, water sources and frac pits) in order to support our drilling activity and the resulting increase in production. We currently believe that our operating cash flows alone will not meet both our short-term working capital requirements and our current 2018 capital expenditure plans. We believe, however, that we have adequate cash on hand and availability under our credit facility to fund any cash flow deficits. Nonetheless, if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our drilling and completion costs, we may further reduce our capital spending program to be within our cash flow.

Although we cannot provide any assurance, we generally attempt to fund our non-acquisition expenditures with our available cash and operating cash flow as adjusted from time to time; however, we may also use our credit facility, or alternative financing sources, to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, timing of lease expirations, actual drilling results, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances we would consider increasing or reallocating our capital spending plans.

Our 2018 capital expenditure plan is exclusive of acquisitions. We do not have a specific acquisition plan, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, exploration and control of operations that will allow us, through our operator, CrownQuest, to apply our operating expertise.

Acquisitions. Our expenditures for acquisitions of proved oil and natural gas properties and undeveloped leasehold acreage totaled approximately $11.1 million and $9.9 million for the nine months ended September 30, 2018 and 2017, respectively. The acquisitions during 2018 and 2017 were comprised of several separate purchases of undeveloped leasehold acreage in West Texas.

Divestitures. We regularly review our asset base to assess the market value versus holding value of existing assets, with a view to optimizing deployed capital. While we generally do not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering our objective of increasing financial flexibility through reduced debt levels. We did not make any significant asset divestitures during the nine months ended September 30, 2018 and 2017.

Exchanges. Occasionally, if it is deemed value-adding, we will enter into exchange agreements with third parties to exchange proved and unproved oil and natural gas properties as part of our strategy to consistently pursue financially viable deals to further block up our acreage and thereby enhance our horizontal well drilling inventory in the Permian Basin. We completed multiple transactions during 2017. We completed multiple transactions during the nine months ended September 30, 2018. The significant transactions are shown below.

On August 22, 2018, we exchanged approximately 2,184 gross (1,849 net) acres of undeveloped leasehold acreage in Glasscock, Martin, and Midland counties, Texas to a third party in exchange for 842 gross (806 net) acres of undeveloped leasehold acreage in Glasscock, Howard, Martin, and Midland counties, Texas. The exchange blocked up our acreage position and thereby enhanced our horizontal well inventory in the Midland Basin. The transaction included the exchange of both proved and unproved oil and natural gas properties. No gain or loss was recognized.

On May 15, 2018, we exchanged approximately 576 gross (221 net) acres of undeveloped leasehold acreage in Midland and Reagan counties, Texas and $0.5 million in cash to a third party in exchange for 1,025 gross (221 net) acres of developed and undeveloped leasehold acreage and working interests in 6 gross (3.6 net) PDP vertical wells in Martin and Howard counties, Texas. The exchange increased our working interest in existing CrownQuest-operated wells and blocked up our acreage position and thereby enhanced our horizontal drilling inventory in the Midland Basin. The transaction included the exchange of both proved and unproved oil and natural gas properties. No gain or loss was recognized.

On May 14, 2018, we exchanged approximately 668 gross (539 net) acres of developed and undeveloped leasehold acreage and working interests in 2 gross (2 net) PDP vertical wells located in Howard, Martin, Dawson, and Borden counties, Texas to a third party in exchange for 564 (460 net) acres of undeveloped leasehold acreage located in Howard County, Texas. The exchange blocked up our acreage position and thereby enhanced our horizontal well inventory in the Midland Basin. This transaction included the exchange of both proved and unproved oil and natural gas properties and was accounted for at fair value and, as a result, we recorded a non-cash gain of $16.1 million.

On May 1, 2018, we exchanged 2,156 gross (1,458 net) acres of developed and undeveloped leasehold acreage and working interests in 1 gross (.5 net) PDP vertical well and 1 gross (.7 net) proved non-producing vertical well located in Midland and Martin counties, Texas to a third party in exchange for 3,274 gross (1,377 net) acres of undeveloped leasehold acreage located in Martin, Howard, Glasscock, and Midland counties, Texas. The exchange blocked up our acreage position and thereby enhanced our horizontal well inventory in the Midland Basin. This transaction included the exchange of both proved and unproved oil and natural gas properties and was accounted for at fair value and, as a result, we recorded a non-cash gain of $47.1 million.

Contractual obligations. In the normal course of business, we enter into various contractual obligations that affect, or could affect, our liquidity. Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, equipment purchase obligations and other obligations.

We had the following contractual obligations at September 30, 2018:

	Payments due by Period				
(in thousands)	**Total**	**2018**	**2019-2020**	**2021-2022**	**2023 and Thereafter**
Long-term debt (a)	$ 1,194,558	$ 253	$ 2,134	$ 2,351	$ 1,189,820
Cash interest expense on debt (b)	501,856	33,442	134,112	133,896	200,406
Asset retirement obligations (c)	22,562	262	2,178	478	19,644
Operating lease obligations (d)	11,483	590	4,273	2,586	4,034
Total	$ 1,730,459	$ 34,547	$ 142,697	$ 139,311	$ 1,413,904

(a) The amounts included in the table above represent principal maturities only.
(b) Cash interest expense on our unsecured senior notes is estimated assuming no principal repayment until their maturity dates. Also included in the "2018" column is accrued interest at September 30, 2018, for our unsecured senior notes of approximately $30.7 million.
(c) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion.
(d) Operating lease obligations are for office space. All of this lease obligation relates to the Canvasback leases, which are eliminated in consolidation.

As set forth in the First Amended and Restated Limited Liability Company Agreement of Silvertip, dated August 31, 2017, we are committed to contribute $14 million to Silvertip, of which $8.7 million has been contributed as of September 30, 2018. The remaining commitment of $5.3 million is due at the time we receive capital call notifications from Silvertip which is unknown at this time. Our capital commitment to Silvertip expires on August 31, 2020.

Off-balance sheet arrangements. Currently, we do not have any off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our credit facility and fixed rate senior notes, equity investments by our partners and strategic divestitures such as the sale of our ownership interest in certain properties, the proceeds of which we used, in part, to acquire additional net acres. We currently believe that our operating cash flows alone will not meet both our short-term working capital requirements and our current 2018 capital expenditure plans. We believe, however, that we have adequate cash on hand and availability under our credit facility to fund any operating cash flow deficits.

The following table summarizes our net decrease in cash and cash equivalents for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,			
(in thousands)	**2018**		**2017**	
Net cash provided by operating activities	$	345,179	$	195,034
Net cash used in investing activities		(484,896)		(318,478)
Net cash provided by financing activities		166,822		54,214
Net increase (decrease) in cash and cash equivalents	$	27,105	$	(69,230)

Cash flow from operating activities. The increase in operating cash flows during the nine months ended September 30, 2018 over 2017 was principally due to increases in oil and natural gas revenues offset by increases in oil and natural gas production costs.

Cash flow from investing activities. During the nine months ended September 30, 2018 and 2017, we invested $479.0 million and $290.9 million, respectively, for additions to, and acquisitions of, oil and natural gas properties. During the nine months ended September 30, 2018 and 2017, we also invested $4.1 million and $32.9 million, respectively, in other property and equipment. Additionally, during 2018, we invested $1.8 million in the Silvertip investment. Cash flows used in investing activities during the nine months ended September 30, 2017 were offset by $7.3 million of proceeds from sales and exchanges of oil and natural gas properties.

Cash flow from financing activities. Net cash provided by financing activities of $166.8 million for the nine months ended September 30, 2018 primarily consisted of the issuance of additional 2025 Senior Notes. Offsetting such borrowing in 2018 were associated debt issuance costs, repayment of our credit facility, repayments of borrowings under the construction loan and distributions to our sole limited partner. Net cash provided by financing activities of $54.2 million for the nine months ended September 30, 2017 consisted of borrowings on our credit facility. Offsetting such borrowings in 2017 were repayments of borrowings under the construction loan and payment of an accrued treasury unit purchase.

We intend to make periodic tax distributions and profit distributions to Holdings in the future to the extent allowed by our credit facility and the indenture and when and if declared by our board of directors of our general partner, CrownRock, GP, LLC, and to the extent consistent with our operating plan and financial strategy.

After January 1, 2018, distributions are made solely to Holdings as our sole limited partner. Holdings must make quarterly tax distributions to the holders of its Series A Preferred Units in cash beginning with the quarter ending March 31, 2018. The amount of such tax distributions for 2018 is expected to be approximately $24.4 million. Since Holdings' only asset is its ownership of the Partnership and the Partnership's general partner, the funds Holdings requires to pay the quarterly tax distributions will be obtained from the Partnership paying quarterly distributions to Holdings. Our credit facility and the indenture governing our 2025 Senior Notes have restrictive covenants limiting dividends and distributions. We estimate that we can pay the necessary quarterly tax distributions to Holdings within the limits of these two agreements

Our credit facility, as amended, has a maturity date of April 1, 2020. At September 30, 2018 and as of the date of this report, the elected borrowing base under our credit facility was $500 million, with no advances outstanding against that borrowing base resulting in the entire $500 million available borrowing capacity. Between scheduled borrowing base redeterminations, we and, if requested by 66.67% of the lenders, the lenders, may each request one special redetermination. Our next scheduled borrowing base redetermination will occur in December 2018.

Advances on the credit facility bear interest, at our option, based on (i) the prime rate of Union Bank, N.A. ("Union Bank Prime Rate") (5.25% at September 30, 2018) or (ii) a Eurodollar rate (substantially equal to the LIBOR). The credit facility's interest rates on Eurodollar rate advances and Union Bank Prime Rate advances varied, with interest margins ranging from 250 to 350 basis points and 150 to 250 basis points, respectively, per annum depending on the debt balance outstanding. We pay commitment fees on the unused portion of the available commitment of 50 basis points per annum.

In conducting our business, we may use various financing sources, including the issuance of fixed and floating rate debt and capital contributions from Holdings. We may also sell assets. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our credit facility. At September 30, 2018, we had $123.2 million of cash on hand.

At September 30, 2018, the elected borrowing base under our credit facility was $500 million, with $500 million available for borrowing. In general, redeterminations are based upon a number of factors, including commodity prices and reserve levels. Upon a redetermination, our borrowing base could be substantially reduced. There is no assurance that our borrowing base will not be reduced.

Debt ratings. We receive debt ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's corporate rating for us is "B+" with a stable outlook. Moody's corporate rating for us is "B2" with a stable outlook. S&P and Moody's consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. Our book capitalization at September 30, 2018 was $2,228.5 million, consisting of debt of $1,194.6 million and partners' capital of $1,033.9 million. Our debt to book capitalization was 53.6% and 52.3% at September 30, 2018 and December 31, 2017, respectively. Our ratio of current assets to current liabilities was 1.70 to 1.00 at September 30, 2018 as compared to 9.45 to 1.00 at December 31, 2017.

Inflation and changes in prices. While the general level of inflation affects certain costs associated with the oil and natural gas industry, inflation has historically had a minimal effect on us. Our results of operations and cash flows are instead affected by changing oil and natural gas prices. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the nine months ended September 30, 2018, we received an average of $59.55 per barrel of oil, $1.42 per Mcf of natural gas and $21.35 per barrel of natural gas liquids before consideration of commodity derivative contracts compared to $47.84 per barrel of oil, $2.10 per Mcf of natural gas and $14.66 per barrel of natural gas liquids during the nine months ended September 30, 2017. Although commodity prices fell significantly during 2015 and 2016, the higher prices during 2017 and the first nine months of 2018 have led to increased activity in the industry and, consequently, rising costs. The cost trends put pressure not only on our operating costs, but also on capital costs.

Critical Accounting Policies and Practices

There have been no material changes in our critical accounting policies during the nine months ended September30, 2018.

Quantitative and Qualitative Disclosure About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at September 30, 2018, and from which we may incur future gains or losses from changes in market commodity prices. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which CrownQuest markets to energy marketing companies and refineries and to a lesser extent our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. We currently require one counterparty to whom we sell our oil and natural gas production to provide collateral support for their obligation to us. We also require another production sales counterparty to route payment through a large financial firm with substantial credit capability. We may, if circumstances dictate, require additional collateral or payment terms in the future.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. At September 30, 2018, the fair value of our financial derivatives is a net liability of $66.5 million. All of our counterparties to these financial derivatives are parties or affiliates of parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party or its affiliates. See Note I of the Notes to Consolidated Financial Statements included in "Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing net income. The fair value of our oil swap agreements at September 30, 2018 was a net liability of $66.5 million. A 10% increase (decrease) in oil prices with all other factors held constant would result in a decrease (increase) in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity contracts of approximately $94.1 million.

Pursuant to our current risk management approach, we seek to enter into derivative contracts to cover a portion of the oil volumes expected to be produced within five years from the proved properties included in the borrowing base under our revolving credit facility.

The following table lists the percentage of our projected oil production from proved properties covered by fixed price swap agreements and the weighted average swap prices at September 30, 2018:

	Projected Proved Production Covered (a)	Weighted Average Swap Prices	
	Crude Oil	Crude Oil	
Remainder of 2018	73%	$	67.81
2019	64%	$	62.07
2020	10%	$	66.15

(a) Based on the internally-prepared reserve evaluation effective October 1, 2018 utilizing oil price of $59.90.

Our actual production may materially vary from the amounts estimated in the October 1, 2018 reserve report.

The fair value of our commodity derivative instruments is determined based on our valuations models. We did not change our valuation method during 2018. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the nine months ended September 30, 2018:

(in thousands)	Derivative Instruments Net Assets (Liabilities) (a) Commodities	
Fair value of contracts outstanding at December 31, 2017	$	57,803
Changes in fair values (b)		(102,958)
Contract maturities		(21,390)
Fair value of contracts outstanding at September 30, 2018	$	(66,545)

(a) Represents the fair values of open derivative contracts subject to market risk.

(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Interest rate risk. Our exposure to changes in interest rates relates primarily to our debt obligations, including our revolving credit facility, which requires us to pay higher interest rate margins as we use a larger percentage of our available commitments. We manage our exposure to changes in interest rates by limiting our variable-rate debt obligations to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates, we may use interest rate derivatives. We would not use interest rate derivatives to modify the overall leverage of our debt portfolio.

OTHER INFORMATION

Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Risk Factors

In addition to the other information set forth in this Quarterly Report, see information under the heading "Risk Factors" in our Annual Report to Holders of 5.625% Senior Notes due 2025 for the Fiscal Year Ended December 31, 2017, filed with the trustee on March 9, 2018. There have been no material changes to the risk factors disclosed in the Annual Report.

Exhibits

Not applicable

SIGNATURES

CrownRock, L.P. has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on November 9, 2018.

CrownRock, L.P.

By: CrownRock, GP, LLC, its general partner

By: /s/ Timothy M. Dunn
Timothy M. Dunn
Chief Executive Officer

By: /s/ Charles W. Wetzel
Charles W. Wetzel
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)