RSP Permian, Inc.
Form 10-Q
May 02, 2018
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark one)

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

For the quarterly period ended March 31, 2018

or

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

For the transition period from to

Commission File Number: 001-36264

RSP Permian, Inc.
(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	90-1022997 (I.R.S. Employer Identification Number)
3141 Hood Street, Suite 500 Dallas, Texas (Address of principal executive offices)	75219 (Zip code)

(214) 252-2700

(Registrant’s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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

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

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

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

The registrant had 159,424,148 shares of common stock outstanding at April 27, 2018.

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GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The following are abbreviations and definitions of certain terms used in this Quarterly Report on Form 10-Q:

“Bbl.” A standard barrel containing 42 U.S. gallons.

“Boe.” One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

“Boe/d.” One Boe per day.

“Btu.” One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

“Completion.” The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“Development project.” A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

“Development well.” A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“Differential.” An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

“Drilled but uncompleted well.” A well that has been drilled but has not undergone the final steps of hydraulic fracturing and procedures necessary to place the well on production.

“Dry hole” or “dry well.” A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

“Economically producible.” The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

“Exploratory well.” A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

“Field.” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“Formation.” A layer of rock that has distinct characteristics that differs from nearby rock.

“Horizontal drilling.” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"MBbl." One thousand barrels.

"MBoe." One thousand Boe.

"Mcf." One thousand cubic feet.

"MMBtu." One million British thermal units.

"MMcf." One million cubic feet.

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“Net acres.” The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

“NGLs.” Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

“NYMEX.” The New York Mercantile Exchange.

“Operator.” The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

“Plugging.” The sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface.

“Prospect.” A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

“Proved developed reserves.” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The SEC provides a complete definition of proved developed reserves in Rule 4-10(a)(6) of Regulation S-X.

“Proved reserves.” The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

“Proved undeveloped reserves” or “PUDs.” Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having PUDs only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years. The SEC provides a complete definition of proved undeveloped reserves in Rule 4-10(a)(31) of Regulation S-X.

“Realized price.” The cash market price less all expected quality, transportation and demand adjustments.

“Recompletion.” The process of re-entering an existing wellbore that is either producing or not producing and completing another formation in an attempt to establish or increase existing production.

“Reserves.” Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non -productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

“Reservoir.” A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“SEC.” The United States Securities and Exchange Commission.

“Spot market price.” The cash market price without reduction for expected quality, transportation and demand adjustments.

“Undeveloped acreage.” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

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“Wellbore.” The hole drilled by the bit that is equipped for oil and natural gas production on a completed well. Also called well or borehole.

“Working interest.” The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

“WTI.” West Texas Intermediate, a type of crude oil used as a benchmark in oil pricing and the underlying commodity of NYMEX oil futures contracts.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements in this Quarterly Report on Form 10-Q, including, without limitation, statements containing the words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “will,” “may,” “should,” “would,” “could” or other similar and statements regarding the Company’s business strategy and plans, constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. We cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements. Our forward-looking statements involve significant 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 our present expectations or projections. Important known factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, uncertainties about our pending merger with Concho Resources Inc., the actual and expected volatility of commodity prices, product supply and demand, competition, access to and cost of capital, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the ability to assimilate acquisitions into our operations, the assumptions underlying production forecasts, the quality of technical data, environmental and weather risks, including the possible impacts of climate change, the ability to obtain environmental and other permits and the timing thereof, government regulation or action, the costs and results of drilling and operations, the availability of equipment, services, resources and personnel required to complete our operating activities, access to and availability of transportation, processing and refining facilities, the financial strength of counterparties to our credit facility and derivative contracts and the purchasers of our production and service providers to us, and acts of war or terrorism. For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see the risk factors described in “Part II, Item 1A. Risk Factors” of this Quarterly Report on Form 10-Q and “Part I, Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2017 and our other filings with the SEC.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.
RSP PERMIAN, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in thousands, except share data)	March 31, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$33,928	$38,102
Accounts receivable	128,198	111,157
Derivative instruments	30,186	64
Total current assets	192,312	149,323
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	7,049,008	6,802,517
Accumulated depletion	(853,720)	(778,596)
Total oil and natural gas properties, net	6,195,288	6,023,921
Other property and equipment, net	56,308	56,798
Total property, plant and equipment	6,251,596	6,080,719
OTHER LONG-TERM ASSETS		
Derivative instruments	4,574	37
Other long-term assets	51,638	40,107
Total other long-term assets	56,212	40,144
TOTAL ASSETS	$6,500,120	$6,270,186
LIABILITIES AND STOCKHOLDERS’ EQUITY		
CURRENT LIABILITIES		
Accounts payable	$54,209	$26,758
Accrued expenses	116,372	119,439
Interest payable	29,604	23,798
Derivative instruments	51,001	36,566
Total current liabilities	251,186	206,561
LONG-TERM LIABILITIES		
Derivative instruments	9,321	5,722
Long-term debt	1,579,751	1,509,128
Deferred taxes	232,500	210,568
Other long-term liabilities	16,565	15,849
Total long-term liabilities	1,838,137	1,741,267
Total liabilities	2,089,323	1,947,828
STOCKHOLDERS’ EQUITY		
Common stock, $.01 par value; 300,000,000 shares authorized, 159,423,086 shares issued and outstanding at March 31, 2018; 158,596,324 shares issued and outstanding at December 31, 2017	1,594	1,586
Additional paid-in capital	4,127,517	4,128,659
Accumulated earnings	281,686	192,113
Total stockholders’ equity	4,410,797	4,322,358
TOTAL LIABILITIES AND STOCKHOLDERS’ EQUITY	$6,500,120	$6,270,186

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31,	
(in thousands, except per share data)	2018	2017
REVENUES		
Oil sales	$251,977	$151,637
Natural gas sales	8,432	7,378
NGLs sales	15,913	10,916
Total revenues	276,322	169,931
OPERATING EXPENSES		
Lease operating expenses	32,135	25,411
Production and ad valorem taxes	16,261	9,469
Depreciation, depletion and amortization	76,122	61,040
Asset retirement obligation accretion	205	153
Impairments of oil and natural gas properties	4,200	125
Exploration expenses	246	2,580
General and administrative expenses	14,334	11,712
Merger and acquisition costs	2,757	4,052
Total operating expenses	146,260	114,542
OPERATING INCOME	130,062	55,389
OTHER INCOME (EXPENSE)		
Other income, net	1,039	720
Net gain on derivative instruments	2,907	17,121
Interest expense	(22,503)	(19,224)
Total other expense	(18,557)	(1,383)
INCOME BEFORE TAXES	111,505	54,006
INCOME TAX EXPENSE	(21,932)	(15,072)
NET INCOME	$89,573	$38,934
Earnings per common share:		
Basic	$0.57	$0.27
Diluted	$0.57	$0.26
Weighted average shares outstanding:		
Basic	157,119	146,054
Diluted	158,309	147,005

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Unaudited)

(in thousands)	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2017	158,596	$1,586	$4,128,659	$ 192,113	$4,322,358
Repurchase and retirement of common stock	(171)	(2)	(6,459)	—	(6,461)
Equity-based compensation	998	10	5,317	—	5,327
Net income	—	—	—	89,573	89,573
BALANCE AT MARCH 31, 2018	159,423	$1,594	$4,127,517	$ 281,686	$4,410,797

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(in thousands)	Three Months Ended March 31, 2018	2017
OPERATING ACTIVITIES:		
Net income	$89,573	$38,934
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	76,122	61,040
Asset retirement obligation accretion	205	153
Impairments of oil and natural gas properties	4,200	125
Equity-based compensation	5,327	3,923
Amortization of loan fees and discount on debt issuance	1,070	1,019
Deferred income taxes	21,932	13,574
Other	(390)	(196)
Net gain on derivative instruments	(2,907)	(17,121)
Net cash payments from settled derivatives	(13,389)	(2,576)
Changes in operating assets and liabilities:		
Accounts receivable	(13,693)	(2,250)
Other assets	(11,478)	(9,131)
Accounts payable	27,123	840
Accrued expenses	(11,692)	816
Interest payable	5,806	17,793
Net cash provided by operating activities	177,809	106,943
INVESTING ACTIVITIES:		
Development of oil and natural gas properties	(236,590)	(116,830)
Acquisitions of oil and natural gas properties	(8,688)	(598,941)
Acquisition of infrastructure assets	—	(18,828)
Investment in unconsolidated subsidiary	—	(188)
Additions to other property and equipment	(244)	(585)
Net cash used in investing activities	(245,522)	(735,372)
FINANCING ACTIVITIES:		
Payment of deferred loan costs	—	(491)
Borrowings under long-term debt	70,000	—
Payments of equity issuance costs	—	(80)
Repurchase and retirement of common stock	(6,461)	(7,516)
Net cash provided by (used in) financing activities	63,539	(8,087)
NET CHANGE IN CASH	(4,174)	(636,516)
CASH AT BEGINNING OF PERIOD	38,102	690,776
CASH AT END OF PERIOD	$33,928	$54,260
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid for interest	$15,627	$412
NON-CASH ACTIVITIES		
Change in accrued capital expenditures	8,624	(2,175)
Common stock issued for oil and gas properties	—	663,854
Release of deposit held in escrow for oil and gas properties	—	64,122
Asset retirement obligation acquired	—	822

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

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NOTE 1—NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Organization and Description of the Business

RSP Permian, Inc., a Delaware corporation ("RSP Inc.," the "Company," "we," "our," or "us"), is an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The vast majority of the Company's acreage is located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin, both sub-basins of the Permian Basin. The Midland Basin properties are primarily in the adjacent counties of Midland, Martin, Andrews, Ector and Glasscock. The Delaware Basin properties are in Loving and Winkler counties. The Company's common stock is listed and traded on the NYSE under the ticker symbol "RSPP."

Proposed Merger with Concho Resources Inc.

On March 27, 2018, we entered into an Agreement and Plan of Merger (the "Merger Agreement") with Concho Resources Inc., a Delaware corporation ("Concho"), and Green Merger Sub Inc., a Delaware corporation and wholly owned subsidiary of Concho ("Merger Sub"), pursuant to which Merger Sub will merge with and into RSP Inc. (the "Merger"), with RSP Inc. surviving the Merger as a wholly owned subsidiary of Concho. Concho's common stock is listed and traded on the NYSE under the ticker symbol "CXO." The closing of the Merger is expected to occur in the third quarter of 2018.

On the terms and subject to the conditions set forth in the Merger Agreement, upon consummation of the Merger, each share of RSP Inc. common stock, par value $0.01 per share, issued and outstanding immediately prior to the effective time of the Merger will be converted into the right to receive from Concho 0.320 of a fully-paid and nonassessable share of common stock, par value $0.001 per share, of Concho ("Concho Shares").

The completion of the Merger is subject to certain customary mutual conditions, including (i) the receipt of the required approvals from the stockholders of RSP Inc. and Concho, (ii) the expiration or termination of the waiting period under the Hart-Scott-Rodino Act, (iii) the absence of any governmental order or law that makes consummation of the Merger illegal or otherwise prohibited, (iv) Concho's registration statement on Form S-4 having been declared effective by the SEC under the Securities Act of 1933, (v) Concho Shares issuable in connection with the Merger having been authorized for listing on the NYSE, upon official notice of issuance, and (vi) the receipt by each party of a customary opinion that the Merger will qualify as a "reorganization" within the meaning of Section 368(a) of the U.S. tax code. The obligation of each party to consummate the Merger is also conditioned upon the other party's representations and warranties being true and correct (subject to certain materiality exceptions) and the other party having performed in all material respects its obligations under the Merger Agreement.

The Merger Agreement contains termination rights for each of Concho and RSP Inc., including, among others, if the consummation of the Merger does not occur on or before October 31, 2018. Upon termination of the Merger Agreement under specified circumstances, including the termination by RSP Inc. in the event of a change of recommendation by Concho's board of directors, Concho would be required to pay RSP Inc. a termination fee of $350.0 million. Upon termination of the Merger Agreement under specified circumstances, including, generally, the termination by Concho in the event of a change of recommendation by the RSP Inc.'s board of directors or by RSP Inc. to enter into an alternative acquisition agreement, RSP Inc. would be required to pay Concho a termination fee of $250.0 million.

On April 20, 2018, Concho filed a registration statement on Form S-4 (the "Form S-4") to register the Concho Shares to be issued in the Merger. The Form S-4 is subject to review by the SEC, and Concho will file one or more amendments to the Form S-4 in the future.

Additional information on the proposed Merger is included in the Form 8-K filed with the SEC on March 28, 2018.

Basis of Presentation

These consolidated financial statements have been prepared by the Company pursuant to the rules and regulations of the SEC and are presented in accordance with generally accepted accounting principles in the United States ("GAAP"). They reflect all adjustments that are, in the opinion of management, necessary for a fair presentation. The consolidated financial statements of the Company include the accounts of the Company and its wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in

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the United States have been omitted pursuant to such rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. The financial statements in this Quarterly Report on Form 10–Q should be read together with the financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2017, which contains a complete summary of the Company's significant accounting policies and disclosures.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities in the financial statements and accompanying notes. The more significant estimates pertain to proved oil, natural gas liquids ("NGLs") and natural gas reserves, asset retirement obligations ("AROs"), equity-based compensation, estimates relating to oil, NGLs and natural gas revenues and expenses, accrued liabilities, the fair market value of assets and liabilities acquired in business combinations, derivatives and income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. Changes in estimates are recorded prospectively.

Significant assumptions are required in the valuation of proved oil, NGLs and natural gas reserves that may affect the amount at which oil and natural gas properties are recorded. Depletion of oil and natural gas properties are determined using estimates of proved oil, NGLs and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price estimates. It is possible that these estimates could be revised at future dates and such revisions could be material.

Reclassifications

Certain reclassifications have been made to prior periods to conform to current period presentation. None of these reclassifications impacted previously reported stockholders' equity, cash flows, or operating income.

Revenue from Contracts with Customers (Topic 606) - ASU 2014-09

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASC 606"). ASC 606 provides a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance including industry specific guidance and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. We adopted ASC 606 in the first quarter of 2018 using the modified retrospective method. The adoption of ASC 606 did not result in a cumulative effect adjustment on our opening accumulated earnings balance in our consolidated balance sheet. Results for reporting periods beginning after January 1, 2018 are presented under ASC 606, while prior period amounts are not adjusted and continue to be reported in accordance with our historical accounting under ASC 605, Revenue Recognition ("ASC 605").

Disaggregation of revenue

In accordance with ASC 606, the Company disaggregates revenues from contracts with customers by product type. All of the Company's revenue is recognized at a point in time when the customer obtains control of the delivered product, which for the Company is primarily at the wellhead. The following table presents our revenues disaggregated by product type and the impact of applying ASC 606 on our current period results:

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(in thousands)	Three Months Ended March 31, 2018		
	As reported (ASC 606)	Historical (ASC 605)	Effect of change
REVENUES			
Oil sales	$251,977	$251,977	$ —
Natural gas sales	8,432	9,601	(1,169)
NGLs sales	15,913	18,074	(2,161)
Total revenues	276,322	279,652	(3,330)
OPERATING EXPENSES			
Lease operating expenses	32,135	35,465	(3,330)
OPERATING INCOME	130,062	130,062	—
NET INCOME	$89,573	$89,573	$ —

Changes to revenues and lease operating expenses shown in the table above are due to the conclusion under ASC 606 that the Company meets the definition of an agent for certain of its gas processing and purchase contracts, thus the fees paid to these service providers are recorded as a deduction to revenues. In contracts where the Company meets the definition of a principal under the control model defined in ASC 606, the fees paid to these service providers are recorded as lease operating expenses.

Oil, natural gas and NGLs sales

We generally sell oil production at the wellhead for a contractually specified index price plus or minus a differential, less transportation costs, and recognize revenue at the net price received.

Under our gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity’s system. For those contracts where we have concluded we are the agent and the midstream processing entity is our customer, we recognize natural gas and NGLs revenues based on the net amount of the proceeds received from the midstream processing entity. Alternatively, for those contracts where we have concluded we are the principal and the ultimate third party is our customer, we recognize revenue on a gross basis, with transportation, gathering, processing and compression fees presented as a component of lease operating expenses in our consolidated statements of operations.

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGLs sales are typically not received for 30 to 90 days after the date production is delivered. At the end of each month, we estimate the amount of production that was delivered to the purchaser and the price that will be received. Variances between our estimates and the actual amounts received, if any, are recorded in the month payment is received. During the first quarter of 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods were not significant.

Practical expedients and exemptions

We do not disclose the value of unsatisfied performance obligations for (i) contracts with an original expected length of one year or less and (ii) contracts for which the variable consideration is allocated entirely to a wholly unsatisfied performance obligation, as allowed under ASC 606. Under our sales contracts, each barrel of oil and NGLs, or Mmbtu of natural gas represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Accounts Receivable

(in thousands)	As of March 31, 2018	As of December 31, 2017
Sale of oil, natural gas and NGLs	$110,722	$95,942
Joint interest owners	17,141	14,880
Federal income tax receivable	335	335
Total accounts receivable	$128,198	$111,157

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Accounts receivable, which are primarily from the sale of oil, NGLs and natural gas, are accrued based on estimates of the volumetric sales and prices the Company believes it will receive. In addition, settled but uncollected derivative contracts, receivables related to joint interest billings and income tax receivables are included in accounts receivable. The Company routinely reviews outstanding balances, assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. The need for an allowance is determined based upon reviews of individual accounts, historical losses, existing economic conditions and other pertinent factors. Bad debt expense was zero for the three months ended March 31, 2018 and 2017, respectively.

Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for its oil and natural gas exploration and production activities. Costs incurred by the Company related to the acquisition of oil and natural gas properties and the cost of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed when determined to be unsuccessful.

The Company may capitalize interest on expenditures for significant exploration and development projects that last more than six months, while activities are in progress to bring the assets to their intended use. The Company has not capitalized any interest as projects generally lasted less than six months. Costs incurred to maintain wells and related equipment, lease and well operating costs and other exploration costs are expensed as incurred.

Capitalized acquisition costs attributable to proved oil and natural gas properties and leasehold costs are depleted using the unit-of-production method based on proved reserves. Capitalized exploration well costs and development costs, including AROs, are depleted using the unit-of-production method based on proved developed reserves. For the three months ended March 31, 2018 and 2017, depletion expense for oil and natural gas producing property was $75.4 million and $60.4 million, respectively. Depletion expense is included in depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The Company’s oil and natural gas properties as of March 31, 2018 and December 31, 2017 consisted of the following:

(in thousands)	March 31, 2018	December 31, 2017
Proved oil and natural gas properties	$4,189,377	$3,936,565
Unproved oil and natural gas properties	2,859,631	2,865,952
Total oil and natural gas properties	7,049,008	6,802,517
Less: Accumulated depletion	(853,720)	(778,596)
Total oil and natural gas properties, net	$6,195,288	$6,023,921

In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the anticipated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of March 31, 2018 and December 31, 2017, there were no costs capitalized in connection with exploratory wells in progress.

Proved oil and natural gas properties are evaluated for impairment annually or whenever events or changes in circumstances indicate that an asset’s carrying amount may not be recoverable. These assets are reviewed for potential impairment at the lowest level for which there are identifiable cash flows available which is the level at which depletion is calculated. To determine if an asset is impaired, the Company compares the carrying value of the asset to the undiscounted future net cash flows by applying estimates of future oil, NGLs and natural gas prices to the estimated future production of oil, NGLs and natural gas reserves over the economic life of the asset and deducting future costs. Future net cash flows are based upon our reservoir engineers' estimates of proved reserves and risk-adjusted probable reserves.

For a property determined to be impaired, an impairment loss equal to the difference between the asset's carrying value and its estimated fair value is recognized. Fair value is estimated to be the present value of the aforementioned expected future net cash flows. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future net cash flows and fair value. No impairment of proved property was recorded for the three months ended March 31, 2018 or 2017. The calculation of expected future net cash flows in impairment evaluations are primarily based on estimates of future oil and natural gas prices, proved reserves and risk-adjusted probable reserve quantities, and estimates of future production and capital costs associated with our proved and risk-adjusted probable reserves. The

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Company's estimates for future oil and natural gas prices used in the impairment evaluations are based on observable prices for the next three years, and then held constant for the remaining lives of the properties.

Unproved property costs and related leasehold expirations are assessed quarterly for potential impairment and when industry conditions dictate an impairment may be possible. For the three months ended March 31, 2018 and 2017, we impaired approximately $4.2 million and $0.1 million, respectively, of unproved oil and natural gas properties, which primarily related to management's expectation that certain leasehold interests would expire and not be renewed.

Proceeds from the sales of individual oil and natural gas properties that are part of a depletion base are credited to accumulated depletion with no immediate impact on income until the entire depletion base is sold. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. Gains and losses arising from the sale of properties are generally included in operating income.

Accrued Expenses

Accrued expenses consist of the following:

(in thousands)	March 31, 2018	December 31, 2017
Accrued capital expenditures	$91,372	$82,748
Other accrued expenses	25,000	36,691
Accrued expenses	$116,372	$119,439

Asset Retirement Obligation

The Company records AROs related to the retirement of long-lived assets at the time a legal obligation is incurred and the liability can be reasonably estimated. AROs are recorded as long-term liabilities with a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future down-hole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of the surface acreage to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes, an adjustment is recorded to both the ARO liability and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

After recording these amounts, the ARO liability is accreted to its future estimated value using the same assumed credit adjusted rate and the associated capitalized costs are depreciated on a unit-of-production basis.

The following is a reconciliation of our ARO liability for the three months ended March 31, 2018:
(in thousands)

Asset retirement obligation at beginning of period	$15,849
Liabilities incurred	789
Liabilities settled	(278)
Accretion expense	205
Asset retirement obligation at end of period	$16,565

Income Taxes

The following is an analysis of the Company’s consolidated income tax expense for the periods indicated:

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(in thousands)	Three Months Ended March 31, 2018	2017
Current	$—	$1,498
Deferred	21,932	13,574
Income Tax Expense	$21,932	$15,072

Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement carrying amounts and tax basis of assets and liabilities, given the provisions of enacted tax laws. Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The Company's policy is to record interest and penalties relating to uncertain tax positions in income tax expense. We have not recognized any interest and penalties relating to unrecognized tax benefits in our consolidated financial statements.

New Accounting Pronouncements

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842) ("ASU 2016-02"). ASU 2016-02 generally requires all lease transactions (with expected lease terms in excess of 12 months) to be recognized on the balance sheet as lease assets and lease liabilities. Public entities are required to apply ASU 2016-02 for annual and interim reporting periods beginning after December 15, 2018 with early adoption permitted. We do not plan to early adopt the standard. We are currently evaluating the impact of ASU 2016-02 on our consolidated financial statements.

NOTE 3—ACQUISITIONS OF OIL AND NATURAL GAS PROPERTY INTERESTS

During the first quarter of 2018, we closed on bolt-on acquisitions of undeveloped acreage in the Delaware Basin for an aggregate total purchase price of $8.7 million.

NOTE 4—DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments

The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price risk inherent in its crude oil and natural gas production. The derivative instruments are recorded at fair value on the consolidated balance sheets and any gains and losses are recognized in current period earnings.

Our commodity derivatives are comprised of the following instruments:

Collars: Each collar transaction has an established price floor and ceiling, and certain collar transactions also include a short put. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume. When the settlement price is below the short put price, the Company receives from its counterparty an amount equal to the difference of the price floor and the short put price multiplied by the hedged contract volume.

Swaps: Each swap transaction has an established fixed price. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

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The following table summarizes all commodity derivative positions as of March 31, 2018:

	Contracts expiring in the period ending:			
	June 30, 2018	September 30, 2018	December 31, 2018	2019
Oil Three-Way Collars:				
Notional volume (Bbl)	1,941,000	1,319,000	1,227,000	—
Weighted average ceiling price ($/Bbl)(1)	$59.07	$ 60.56	$ 60.96	$ —
Weighted average floor price ($/Bbl)(1)	$47.11	$ 47.79	$ 48.00	$ —
Weighted average short put price ($/Bbl)(1)	$37.11	$ 37.79	$ 38.00	$ —
Oil Costless Collars:				
Notional volume (Bbl)	516,000	1,212,000	1,058,000	2,555,000
Weighted average ceiling price ($/Bbl)(1)	$60.20	$ 60.10	$ 60.11	$ 58.04
Weighted average floor price ($/Bbl)(1)	$45.00	$ 46.33	$ 46.52	$ 52.50
Oil Swaps:				
Notional volume (Bbl)	698,000	322,000	322,000	2,555,000
Weighted average swap price ($/Bbl)(1)	$62.97	$ 55.77	$ 55.77	$ 55.74
Mid-Cush Differential (Basis) Swaps:				
Notional volume (Bbl)	2,730,000	2,760,000	2,760,000	2,555,000
Weighted average swap price ($/Bbl)(2)	$(0.42)	$ (0.42)	$ (0.42)	$ (0.29)

(1) The oil derivative contracts are settled based on the arithmetic average of the closing settlement price for the front month contract NYMEX price of West Texas Intermediate Light Sweet Crude.
(2) The Mid-Cush swap contracts are settled based on the difference in the arithmetic average during the calculation period of WTI MIDLAND ARGUS and WTI ARGUS prices in the Argus Americas Crude publication for the relevant period.

Derivative Fair Values and Gains

The following table presents the fair value of our derivative instruments. Our derivatives are presented as separate line items in our consolidated balance sheets as current and noncurrent derivative instrument assets and liabilities based on the expected settlement dates of the instruments. The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements. However, the fair value amounts are presented on a gross basis in our consolidated balance sheets and do not reflect the netting of asset and liability positions permitted under the terms of the Company's master netting arrangements. See Note 5 for further discussion related to the fair value of the Company's derivatives.

	Assets		Liabilities	
(in thousands)	March 31, 2018	December 31, 2017	March 31, 2018	December 31, 2017
Derivative Instruments:				
Current amounts	$30,186	$ 64	$51,001	$ 36,566
Noncurrent amounts	4,574	37	9,321	5,722
Total derivative instruments	$34,760	$ 101	$60,322	$ 42,288

Gains and losses on derivatives are reported in the consolidated statements of operations.

The following represents the Company’s reported gains on derivative instruments for the periods presented:

(in thousands)	Three Months Ended March 31, 2018	2017
Net gain on derivative instruments	$2,907	$17,121

Credit-Risk Related Contingent Features in Derivatives

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None of the Company’s derivative instruments contain credit-risk related contingent features. No amounts of collateral were posted by the Company related to net positions as of March 31, 2018 and December 31, 2017.

NOTE 5—FAIR VALUE MEASUREMENTS

We value our derivatives and other financial instruments according to FASB ASC 820, Fair Value Measurements and Disclosures, which defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (“exit price”) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

•Level 1—Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered 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—Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
•Level 3—Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs that are not corroborated by market data and may reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Reclassifications of fair value among Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. There were no transfers among Level 1, Level 2 or Level 3 during the three months ended March 31, 2018.

Fair Value Measurement on a Recurring Basis

Fair value of commodity derivative instruments

The fair value of derivative financial instruments is determined utilizing industry standard models incorporating assumptions and inputs, most of which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors.

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The following table presents a summary of the estimated net fair value of our commodity derivative instruments as of March 31, 2018 and December 31, 2017.

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of March 31, 2018:				
Commodity derivative instruments	$ —	$ (25,562)	$ —	$ (25,562)

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2017:				
Commodity derivative instruments	$ —	$ (42,187)	$ —	$ (42,187)

Fair value of other financial instruments

Our financial instruments include cash and cash equivalents, accounts receivable and payable and accrued expenses. The carrying amount of these instruments approximates fair value because of their short-term nature. The carrying value of our borrowings under our revolving credit facility ("Revolving Credit Facility") approximate fair value as these are subject to short-term floating interest rates that approximate the rates available to us for those periods. The estimated fair values of our senior notes are presented below. The estimated fair value of our 5.25% senior unsecured notes due January 15, 2025 (“2025 Senior Notes”) and 6.625% senior unsecured notes due October 1, 2022 (“2022 Senior Notes”) have been calculated based on quoted prices in active markets and are classified as Level 1.

The following table presents a summary of the estimated fair value of our senior notes as of March 31, 2018 and December 31, 2017.

	March 31, 2018			
(in thousands)	Level 1	Level 2	Level 3	Total fair value
2025 Senior Notes	$466,340	$ —	$ —	$ 466,340
2022 Senior Notes	732,963	—	—	732,963
	December 31, 2017			
(in thousands)	Level 1	Level 2	Level 3	Total fair value
2025 Senior Notes	$464,022	$ —	$ —	$ 464,022
2022 Senior Notes	734,706	—	—	734,706

Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company’s estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. Additionally, fair value is used to determine the inception value of the Company’s AROs. The inputs used to determine such fair value are primarily based upon assumptions of the estimated current abandonment costs, discount rate, inflation rate and timing associated with the incurrence of these costs. Our estimated abandonment costs are obtained primarily from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition or costs incurred historically for similar work. Additions to the Company’s AROs represent a nonrecurring Level 3 measurement.

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

NOTE 6—LONG-TERM DEBT

Long-term debt consists of the following:

(in thousands)	March 31, 2018	December 31, 2017
Revolving Credit Facility	$445,000	$375,000
5.25% Senior Notes due 2025	450,000	450,000
6.625% Senior Notes due 2022	700,000	700,000
Less: Discount	(900)	(950)
Less: Debt issuance costs	(14,349)	(14,922)
Total long-term debt	$1,579,751	$1,509,128

Revolving Credit Facility

As of March 31, 2018, the borrowing base under our amended and restated credit agreement was $1.5 billion, with a Company-elected commitment of $900.0 million, and lender commitments of $2.5 billion. The maturity date of the Revolving Credit Facility is December 19, 2021. The borrowing base under the Revolving Credit Facility remains subject to semi-annual review and redetermination by the lenders pursuant to the term of the credit agreement. The redetermination of the borrowing base occurs in May and November of each year and, among other things, depends on the volumes of proved oil, NGLs and natural gas reserves and an estimate of associated cash flows, and commodity hedge positions. As of March 31, 2018, we had $445.0 million in borrowings, $1.9 million of letters of credit outstanding and $453.1 million of borrowing capacity under our Revolving Credit Facility.

The Company's credit agreement requires that we maintain the following two financial ratios:

•a working capital ratio, which is the ratio of consolidated current assets (includes unused commitments under its Revolving Credit Facility and excludes restricted cash and derivative assets) to consolidated current liabilities (excluding the current portion of long-term debt under the Revolving Credit Facility and derivative liabilities), of not less than 1.0 to 1.0;
•a leverage ratio, which is the ratio of the sum of all of the Company’s debt to the consolidated EBITDAX (as defined in the credit agreement) for the four fiscal quarters then ended, of not greater than 4.25 to 1.0.

Our credit agreement also contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, make loans to others, make investments, enter into mergers, make or declare dividends, enter into commodity hedges exceeding a specified percentage or our expected production, enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness, incur liens, sell assets, enter into transactions with affiliates or engage in certain other transactions without the prior consent of the lenders.

The Company was in compliance with such covenants and ratios as of March 31, 2018.

Principal amounts borrowed under our Revolving Credit Facility are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing at a Eurodollar rate or at the adjusted base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted London Interbank Offered Rate (“LIBOR”) (equal to the quotient of: (i) the LIBOR rate; divided by (ii) a percentage equal to 100% minus the maximum rate on such date at which the administrative agent is required to maintain reserves on “Eurocurrency Liabilities,” as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 150 basis points to 250 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank’s referenced rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 50 basis points to 150 basis points, depending on the percentage of our borrowing base utilized, plus a commitment fee ranging from 37.5 basis points to 50 basis points charged on the undrawn commitment amount. On March 31, 2018, our weighted average interest rate was approximately 3.9%.

2025 Senior Notes

On December 27, 2016, the Company issued $450.0 million of 5.25% senior unsecured notes at par through a private placement. In November 2017, the Company exchanged these notes for registered notes with the same terms. The 2025 Senior Notes will mature on January 15, 2025. The notes are senior unsecured obligations that rank equally with all of our future senior indebtedness, are effectively subordinated in rights to our assets constituting collateral held by all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including indebtedness under our Revolving Credit Facility, and will rank senior to any future subordinated indebtedness of the Company. Interest on the 2025

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Senior Notes is payable semi-annually on January 15 and July 15. On or after January 15, 2020, the Company may redeem some or all of the 2025 Senior Notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2023 and thereafter. In addition, prior to January 15, 2020, on any one or more occasions, the Company may redeem all or part of the 2025 Senior Notes at a redemption price of 100% of the principal amount of the notes redeemed, plus an applicable make-whole premium along with accrued and unpaid interest.

In the event of certain changes in control of the Company, each holder of the 2025 Senior Notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The 2025 Senior Notes are guaranteed on a senior unsecured basis by each of our consolidated subsidiaries. The subsidiary guarantees are full and unconditional and joint and several, and any of our subsidiaries other than the subsidiary guarantors are minor. RSP Inc. does not have independent assets or operations. The terms of the notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. The Company was in compliance with the provisions of the indenture governing the 2025 Senior Notes as of March 31, 2018.

2022 Senior Notes

On September 26, 2014, the Company issued $500.0 million of 6.625% senior unsecured notes at par through a private placement. In June 2015, the Company exchanged these notes for registered notes with the same terms. On August 10, 2015, the Company issued an additional $200.0 million of the 6.625% senior unsecured notes at 99.25% of the principal amount through a private placement. In March 2016, the Company exchanged these additional notes for registered notes with the same terms. The 2022 Senior Notes will mature on October 1, 2022. The notes are senior unsecured obligations that rank equally with all of our future senior indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowings under our Revolving Credit Facility, and will rank senior to any future subordinated indebtedness of the Company. Interest on the 2022 Senior Notes is payable semi-annually on April 1 and October 1. The Company may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.969% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter.

In the event of certain changes in control of the Company, each holder of the 2022 Senior Notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The 2022 Senior Notes are guaranteed on a senior unsecured basis by each of our consolidated subsidiaries. The subsidiary guarantees are full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors are minor. The terms of the notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. The Company was in compliance with the provisions of the indenture governing the 2022 Senior Notes as of March 31, 2018.

NOTE 7—COMMITMENTS AND CONTINGENCIES

Legal and Environmental Matters

The Company is party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect, individually or in the aggregate, on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then-current status of the matters.

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed as incurred. We have established procedures for the ongoing evaluation of our operations to identify potential environmental exposures and to comply with regulatory policies and procedures.

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Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed.

Liabilities are recorded when we determine the potential exposure related to, but not limited to, legal matters, environmental assessments and/or clean-ups, is probable and estimable. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both March 31, 2018 and December 31, 2017, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Contractual Obligations

For the three months ended March 31, 2018, the Company had no material changes in its contractual commitments and obligations from amounts listed in Note 7 in the notes to our consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2017.

NOTE 8—EQUITY-BASED COMPENSATION

The Company's 2014 Long Term Incentive Plan ("LTIP") provides for granting restricted stock awards and performance-based restricted stock awards to employees, consultants and directors of the Company and its affiliates who perform services for the Company. Equity-based compensation expense, which was recorded in general and administrative expenses, was $5.3 million and $3.9 million for the three months ended March 31, 2018 and 2017, respectively.

Restricted Stock Awards

The following table represents restricted stock award activity for the three months ended March 31, 2018:

	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	687,277	$ 32.04
Restricted shares granted	437,608	35.96
Restricted shares canceled	(770)	30.66
Restricted shares vested	(320,001)	30.04
Restricted shares outstanding, end of period	804,114	$ 34.97

As of March 31, 2018, the Company had unrecognized compensation expense of $26.3 million related to restricted stock awards which is expected to be recognized over a weighted average period of 2.2 years.

Performance-Based Restricted Stock Awards

We granted performance-based restricted stock awards to certain officers of the Company. The payout of these awards varies depending on the Company's total shareholder return in comparison to an identified peer group. We granted 496,537 performance-based restricted stock awards in February 2018 that allow for a payout between 0% and 100%, with a cliff vesting period of three years.

The following table represents performance-based restricted stock award activity for the three months ended March 31, 2018:

	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	1,001,079	$ 21.14
Restricted shares granted (1)	496,537	23.96
Restricted shares vested (1)	(143,824)	31.74
Restricted shares outstanding, end of period	1,353,792	$ 21.05

(1) Performance-based restricted shares granted or vested reflect the number of shares granted or vested at a 100% of the target payout. The actual payout of the shares granted may be between 0% and 200% depending on the date of the grant and Company's total shareholder return in comparison to an identified peer group.

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As of March 31, 2018, the Company had unrecognized compensation expense of $19.4 million related to performance-based restricted stock awards which is expected to be recognized over a weighted average period of 1.8 years.

NOTE 9—EARNINGS PER SHARE

The Company’s basic earnings per share amounts have been computed using the two-class method based on the weighted-average number of shares of common stock outstanding for the period. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended March 31,	
(in thousands, except per share data)	2018	2017
Numerator:		
Net income available to stockholders	$89,573	$38,934
Basic net income allocable to participating securities (1)	448	195
Income available to stockholders	$89,125	$38,739
Denominator:		
Weighted average number of common shares outstanding - basic	157,119	146,054
Effect of dilutive securities:		
Restricted stock	1,190	951
Weighted average number of common shares outstanding - diluted	158,309	147,005
Net earnings per share:		
Basic	$0.57	$0.27
Diluted	$0.57	$0.26

(1) Restricted share awards that contain non-forfeitable rights to dividends are participating securities and, therefore, are included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes in “Part I, Item 1. Financial Statements.” The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions and resources. Please see “Cautionary Statement Concerning Forward-Looking Statements” and “Part II, Item 1A. Risk Factors” elsewhere in this Quarterly Report on Form 10-Q and “Part I, Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2017.

Overview and Outlook

We are an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The vast majority of the Company’s acreage is located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin, both sub-basins of the Permian Basin.

Our financial and operating performance in the first three months of 2018 include the following highlights:

- Increased our average daily production rate by 39% for the first quarter of 2018 as compared to the same period in 2017.
- Participated in drilling 36 gross horizontal wells (22 operated) and completed 44 gross horizontal wells (31 operated) during the first quarter of 2018.

Recent significant events that occurred during the first quarter of 2018 include the following:

- On March 27, 2018, we entered into a merger agreement (the “Merger Agreement”) with Concho Resources Inc ("Concho"), and Green Merger Sub Inc., a wholly owned subsidiary of Concho (“Merger Sub”). Pursuant to the Merger Agreement, Merger Sub will merge with and into RSP Inc. (the “Merger”), with RSP Inc. surviving the Merger as a wholly owned subsidiary of Concho. The Merger is expected to close in the third quarter of 2018, subject to approvals from the stockholders of RSP Inc. and Concho and certain other conditions. See Note 1 in the notes to our consolidated financial statements for further discussion. Shareholders of RSP Inc. will receive 0.320 of a share of Concho common stock in exchange for each share of RSP Inc's common stock, representing consideration to each shareholder of RSP Inc. of $50.24 per share based on the closing price of Concho common stock on March 27, 2018. The consideration represents an approximately 29% premium to the $38.92 closing price of RSP Inc. common stock on March 27, 2018.

Our average daily production rate during the first quarter of 2018 was 62,778 Boe/d, a 39% increase from the first quarter 2017 average daily production of 45,189 Boe/d. Oil production was 72% of total production on a volumetric basis and 91% of our total revenues in the first quarter of 2018, compared with 75% of total production on a volumetric basis and 90% of our total revenues in the first quarter of 2017.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including:

- production volumes;
- revenues on the sale of oil, NGLs and natural gas, including the effect of our commodity derivative contracts on our production;

- operating expenses; and
- capital efficiency.

Due to the inherent volatility in commodity prices, we have historically used commodity derivative instruments, such as collars, swaps and puts, to hedge price risk associated with a significant portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in commodity prices and may partially limit our potential gains from future increases in prices. Our commodity derivative instruments are not held for trading purposes. We do not speculate on commodity prices but rather attempt to hedge a portion of our physical production in order to protect our returns. Our revolving credit facility ("Revolving Credit Facility") limits our ability to enter into commodity hedges covering greater than 85% of our reasonably projected production volume.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. We are not under an obligation to hedge a specific portion of our production. For information regarding the summary of open positions, see Note 4 in the notes to our consolidated financial statements.

2018 Capital Budget

Our board of directors has approved an initial capital budget for drilling, completion, and infrastructure and other for 2018 of approximately $815 million to $895 million. We continuously monitor commodity prices, our cash flow and returns to determine adjustments to our capital budget. We intend to allocate our 2018 capital budget approximately as follows:

•$725 million to $785 million for drilling and completion activities; approximately 10% of which is non-operated; and
•$90 million to $110 million for infrastructure and other.

During the first quarter of 2018, our capital expenditures totaled approximately $241.8 million, which included approximately $194.5 million spent on drilling and completion activities and approximately $47.3 million spent on infrastructure and other expenditures. We added a third completion crew in the first quarter of 2018, earlier than initially anticipated to reduce our inventory of drilled but uncompleted wells on an accelerated basis. We anticipate that our 2018 capital expenditures will be funded with cash generated by operations and borrowings under our Revolving Credit Facility.

Our 2018 capital budget excludes acquisitions and additions to leasehold and is subject to change depending upon a number of factors, including the closing of the pending Merger, prevailing and anticipated prices for oil, NGLs and natural gas, results of horizontal drilling and completions, economic and industry conditions at the time of drilling, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

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Results of Operations

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Oil, NGLs and Natural Gas Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Three Months Ended March 31,		Change	
	2018	2017	$	%
Revenues (in thousands, except percentages):				
Oil sales	$251,977	$151,637	$100,340	66 %
Natural gas sales	8,432	7,378	1,054	14
NGLs sales	15,913	10,916	4,997	46
Total revenues	$276,322	$169,931	$106,391	63 %
Average sales prices (1):				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$61.87	$50.01	$11.86	24 %
Oil (per Bbl) (after impact of cash settled derivatives)	58.50	49.02	9.48	19
Natural gas (per Mcf) (excluding impact of cash settled derivatives)	1.98	2.52	(0.54)	(21)
Natural gas (per Mcf) (after impact of cash settled derivatives)	1.98	2.59	(0.61)	(24)
NGLs (per Bbl)	18.33	19.96	(1.63)	(8)
Total (per Boe) (excluding impact of cash settled derivatives)	$48.91	$41.78	$7.13	17 %
Total (per Boe) (after impact of cash settled derivatives)	$46.48	$41.09	$5.39	13 %
Production:				
Oil (MBbls)	4,073	3,032	1,041	34 %
Natural gas (MMcf)	4,254	2,926	1,328	45
NGLs (MBbls)	868	547	321	59
Total (MBoe)	5,650	4,067	1,583	39 %
Average daily production volume:				
Total (Boe/d)	62,778	45,189	17,589	39 %

(1) Average realized natural gas and NGLs prices in the first quarter of 2018 were impacted by the adoption of Accounting Standards Update 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASC 606"), which requires certain transportation, gathering, processing and compression fees paid to our midstream processing entity to be recorded as a deduction to revenues. Prior to 2018, these fees were recorded in lease operating expenses. The reclassification of lease operating expenses as a deduction to revenues does not have an effect on our reported net income or cash flows from operations. See Note 2 in the notes to our consolidated financial statements for discussion and impact on our financial statements from the adoption of ASC 606.

The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the periods indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues. The NYMEX WTI futures price is a widely-used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport oil to the transportation hubs or refineries. The NYMEX Henry Hub price of natural gas is a widely-used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, depending on pricing, liquids rich natural gas with a high Btu content may sell at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered.

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	Three Months Ended March 31,	
	2018	2017
Average realized oil price ($/Bbl)	$61.87	$50.01
Average NYMEX ($/Bbl)	62.87	51.91
Differential to NYMEX	(1.00)	(1.90)
Average realized oil price to NYMEX percentage	98%	96%
Average realized natural gas price ($/Mcf) (1)	$1.98	$2.52
Average NYMEX ($/Mcf)	3.00	3.32
Differential to NYMEX	(1.02)	(0.80)
Average realized natural gas price to NYMEX percentage	66%	76%
Average realized NGL price ($/Bbl) (1)	$18.33	$19.96
Average NYMEX oil price ($/Bbl)	62.87	51.91
Average realized NGL price to NYMEX oil price percentage	29%	38%

(1) Average realized natural gas and NGLs prices in the first quarter of 2018 were impacted by the adoption of ASC 606, which requires certain transportation, gathering, processing and compression fees paid to our midstream processing entity to be recorded as a deduction to revenues. Prior to 2018, these fees were recorded in lease operating expenses. The reclassification of lease operating expenses as a deduction to revenues does not have an effect on our reported net income or cash flows from operations. See Note 2 in the notes to our consolidated financial statements for discussion and impact on our financial statements from the adoption of ASC 606.

Our average realized oil price as a percentage of the average NYMEX price was 98% and 96% for the three months ended March 31, 2018 and 2017, respectively. All of our oil contracts are impacted by the Midland-Cushing differential, which was a positive $0.37 and $0.64 per Bbl for the first quarters of 2018 and 2017, respectively.

Oil revenues increased 66% to $252.0 million for the three months ended March 31, 2018 from $151.6 million for the three months ended March 31, 2017 as a result of an increase in oil production volumes of 1,041 MBbls, or 34%, and a $11.86 per Bbl increase, or 24%, in our average realized price for oil.

Natural gas revenues increased 14% to $8.4 million for the three months ended March 31, 2018 from $7.4 million for the three months ended March 31, 2017 as a result of an increase in natural gas production volumes of 1,328 MMcf, or 45%. The increase was partially offset by a $0.54 per Mcf decrease, or 21%, in our average realized natural gas price.

NGLs revenues increased 46% to $15.9 million for the three months ended March 31, 2018 from $10.9 million for the three months ended March 31, 2017 as a result of an increase in NGLs production volumes of 321 MBbls, or 59%. The increase was partially offset by a $1.63 per Bbl decrease, or 8%, in our average realized price for NGLs.

Our higher production volumes for all products were primarily a result of increased production from our drilling program, along with the full period impact of our acquisitions that closed during 2017.

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Operating Expenses. The following table summarizes our expenses for the periods indicated:

	Three Months Ended March 31,		Change	
	2018	2017	$	%
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$32,135	$25,411	$6,724	26 %
Production and ad valorem taxes	16,261	9,469	6,792	72
Depreciation, depletion and amortization	76,122	61,040	15,082	25
Asset retirement obligation accretion	205	153	52	34
Impairments of oil and natural gas properties	4,200	125	4,075	NM
Exploration expenses	246	2,580	(2,334)	(90)
General and administrative expenses	14,334	11,712	2,622	22
Merger and acquisition costs	2,757	4,052	(1,295)	(32)
Total operating expenses	$146,260	$114,542	$31,718	28 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$5.44	$5.40	$0.04	1 %
Gathering and transportation (1)	0.25	0.85	(0.60)	(71)
Production and ad valorem taxes	2.88	2.33	0.55	24
Depreciation, depletion and amortization	13.47	15.01	(1.54)	(10)
Asset retirement obligation accretion	0.04	0.04	—	—
Impairments of oil and natural gas properties	0.74	0.03	0.71	NM
Exploration expenses	0.04	0.63	(0.59)	(94)
General and administrative - cash component	1.60	1.91	(0.31)	(16)
General and administrative - stock comp (2)	0.94	0.96	(0.02)	(2)
Merger and acquisition costs	0.49	1.00	(0.51)	(51)
Total operating expenses per Boe	$25.89	$28.16	$(2.27)	(8)%

(1) Gathering and transportation costs in the first quarter of 2018 were impacted by the adoption of ASC 606, which requires certain transportation, gathering, processing and compression fees paid to our midstream processing entity to be recorded as a deduction to revenues. Prior to 2018, these fees were recorded as gathering and transportation and were included in lease operating expenses. The reclassification of lease operating expenses as a deduction to revenues does not have an effect on our reported net income or cash flows from operations. See Note 2 in the notes to our consolidated financial statements for discussion and impact on our financial statements from the adoption of ASC 606.
(2) Represents non-cash compensation expense related to restricted stock awards and performance share awards granted as part of the Company's compensation and retention program.

Lease Operating Expenses. Lease operating expenses increased to $32.1 million for the three months ended March 31, 2018 from $25.4 million for the three months ended March 31, 2017 due to a 39% increase in production associated with new wells drilled and completed during 2017 and 2018 and the impact of 2017 acquisitions. This was partially offset by lower gathering and transportation expenses primarily related to the adoption of ASC 606 in the current period as described in Note 2 in the notes to our consolidated financial statements. On a per-Boe basis, lease operating expense, excluding gathering and transportation costs, for the three months ended March 31, 2018 remained consistent with 2017. Gathering and transportation costs, which are included in lease operating expenses, were $1.4 million and $3.4 million for the three months ended March 31, 2018 and 2017, respectively. On a per-Boe basis, gathering and transportation costs were $0.25 and $0.85 for the three months ended March 31, 2018 and 2017, respectively. The decrease in our gathering and transportation costs was primarily related to the adoption of ASC 606 in the current period.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 72% to $16.3 million for the three months ended March 31, 2018 from $9.5 million for the three months ended March 31, 2017. The increase was primarily due to higher production volumes and revenues, as well as higher property taxes related to Delaware basin properties. On a per-Boe basis, production and ad valorem taxes increased to $2.88 per Boe for the three months ended March 31, 2018 from $2.33 per Boe in 2017 due to higher oil prices.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (“DD&A”) expense increased 25% to $76.1 million for the three months ended March 31, 2018 from $61.0 million for the three months ended March 31, 2017 due to

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increased production partially offset by lower depletion rate per Boe. The DD&A rate decreased 10% to $13.47 per Boe for the three months ended March 31, 2018 from $15.01 per Boe for the three months ended March 31, 2017. The decrease in depletion per Boe in 2018 was due to an increase in our reserve volumes from successful drilling activities, partially offset by an increase in capitalized costs in proved property.

Impairment of Oil and Natural Gas Properties. We incurred $4.2 million and $0.1 million of impairment expense for the three months ended March 31, 2018 and 2017, respectively. These impairments recorded in both periods related to unproved properties with acreage lease expirations that we do not intend to extend or develop. We may incur additional unproved property impairments in the future due to acreage expirations and changes in development plans. We may incur proved property impairments in the future if commodity prices experience sustained declines. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and gas prices, estimates of proved reserves and future capital expenditures and production costs.

Exploration Expenses. Exploration expense decreased to $0.2 million for the three months ended March 31, 2018 from $2.6 million for the three months ended March 31, 2017 due to lower expenditures on geological and geophysical activity related to projects in the Delaware Basin.

General and Administrative Expenses. General and administrative expenses increased to $14.3 million for the three months ended March 31, 2018, from $11.7 million for the three months ended March 31, 2017 primarily due to an increase in the employee headcount and related expense including additional equity-based compensation. Equity-based compensation expense, which was recorded in general and administrative expenses, was $5.3 million and $3.9 million for the three months ended March 31, 2018 and 2017, respectively.

Merger and acquisition costs. Merger and acquisition costs of $2.8 million for the three months ended March 31, 2018 were related to costs (professional fees, advisory fees and other miscellaneous expenses) incurred as a result of the Merger Agreement. We expect incremental costs and the total merger and acquisition costs to be between $30.0 million and $40.0 million upon a successful closing of the Merger. Merger and acquisition costs of $4.1 million for the three months ended March 31, 2017 were related to costs associated with the acquisition of Silver Hill E&P II, LLC ('Silver Hill"), which closed on March 1, 2017.

Other Income and Expenses. The following table summarizes our other income and expenses:

	Three Months Ended March 31,		Change	
	2018	2017	$	%
Other income (expense) (in thousands, except percentages):				
Other income, net	$1,039	$720	$319	44 %
Net gain on derivative instruments	2,907	17,121	(14,214)	(83)%
Interest expense	(22,503)	(19,224)	(3,279)	17 %
Total other expense	$(18,557)	$(1,383)	$(17,174)	1,242 %

Net Gain on Derivative Instruments. During the three months ended March 31, 2018, we recorded a $2.9 million net gain on derivative instruments as compared to $17.1 million during the three months ended March 31, 2017. The change was a result of new contracts on derivative positions entered into and the higher future commodity price outlook as of March 31, 2018 as compared to March 31, 2017.

Interest Expense. During the three months ended March 31, 2018, we recorded $22.5 million of interest expense as compared to $19.2 million during the three months ended March 31, 2017. The increase in interest expense was primarily due to increased borrowings under our Revolving Credit Facility.

Income Tax Expense. During the three months ended March 31, 2018, we recorded $21.9 million of income tax expense compared to $15.1 million during the three months ended March 31, 2017. The increase was largely related to a pretax book income during the three months ended March 31, 2018 compared to the three months ended March 31, 2017, partially offset by lower federal corporate tax rate which decreased from 35% to 21% as a result of the Tax Cuts and Jobs Act enacted in December 2017.

Capital Requirements and Sources of Liquidity

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We define liquidity as available borrowing capacity under our Revolving Credit Facility plus cash and cash equivalents. Our primary sources of liquidity have been proceeds from equity offerings, borrowings under our Revolving Credit Facility, proceeds from the issuance of senior notes, and cash flows from operations. To date, our primary use of capital has been for the acquisition, development, exploration and exploitation of oil and natural gas properties. In October 2017, we increased the borrowing base under our Revolving Credit Facility to $1.5 billion from $1.1 billion. We maintained our elected commitment amount of $900.0 million. At March 31, 2018, we had $453.1 million of borrowing capacity under our Revolving Credit Facility and $33.9 million of cash on hand for total liquidity of $487.0 million.

The following table summarizers our liquidity position as of March 31, 2018:

(in thousands)	March 31, 2018
Revolving Credit Facility elected commitment amount	$900,000
Revolving Credit Facility borrowings	(445,000)
Letters of credit	(1,933)
Available borrowing capacity	453,067
Cash and cash equivalents	33,928
Liquidity	$486,995

During the first quarter of 2018, our capital expenditures totaled approximately $241.8 million, which included approximately $194.5 million spent on drilling and completion activities and approximately $47.3 million spent on infrastructure and other expenditures. Our capital expenditures were funded with cash generated by operations and borrowings under our Revolving Credit Facility.

We operate a high percentage of our acreage; therefore, the amount and timing of these capital expenditures are largely discretionary. We may elect to defer a portion of planned capital expenditures depending on a variety of factors, including: returns generated by our drilling program, the level of our expenditures in relation to our cash flow from operations, the success of our drilling activities; prevailing and anticipated prices for oil, NGLs and natural gas; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; drilling, completion and acquisition costs; and the level of participation by other working interest owners.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our Revolving Credit Facility to execute our current capital program excluding any acquisitions we may consummate. However, future cash flows are subject to a number of variables, including the level of oil, NGLs and natural gas production and prices, acquisitions and the level of capital expenditures required to develop our properties. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital, we may seek such capital through borrowings under our Revolving Credit Facility, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot provide assurance that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Working Capital

Our working capital, which we define as current assets minus current liabilities, was a deficit of $58.9 million and $57.2 million at March 31, 2018 and December 31, 2017, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $33.9 million and $38.1 million at March 31, 2018 and December 31, 2017, respectively. Due to the amounts that accrue related to our drilling program, we may incur incremental working capital deficits in the future. We expect that our cash flows from operating activities and availability under our Revolving Credit Facility will be sufficient to fund our working capital needs, excluding any acquisitions we may consummate. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, NGLs and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

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For the three months ended March 31, 2018, we had no material changes in our contractual commitments and obligations from amounts listed under “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Capital Requirements and Sources of Liquidity - Contractual Obligations” in our Annual Report on Form 10-K for the year ended December 31, 2017.

Off-Balance Sheet Arrangements

As of March 31, 2018, we did not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources and would be considered material to investors.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Three Months Ended March 31,	
(in thousands)	2018	2017
Net cash provided by operating activities	$177,809	$106,943
Net cash used in investing activities	(245,522)	(735,372)
Net cash provided by (used in) financing activities	63,539	(8,087)

For the three months ended March 31, 2018, our net cash provided by operating activities was $177.8 million as compared to $106.9 million for the three months ended March 31, 2017. The increase was primarily attributable to increased production and higher realized oil prices.

For the three months ended March 31, 2018, our net cash used in investing activities was $245.5 million primarily related to the drilling and completion activity of our oil and natural gas properties in the Midland and Delaware basins. For the three months ended March 31, 2017, our net cash used in investing activities was $735.4 million due to oil and natural gas property acquisitions of $598.9 million primarily related to the Delaware Basin properties purchased in the Silver Hill acquisition and $116.8 million of cash used for the drilling and completion activity of our oil and natural gas properties in the Midland and Delaware basins.

For the three months ended March 31, 2018, our net cash provided by financing activities was $63.5 million primarily due to additional borrowings under our Revolving Credit Facility. For the three months ended March 31, 2017 our net cash used in financing activities was $8.1 million primarily related to repurchases of our common stock to satisfy statutory tax withholding obligations arising upon the vesting of restricted shares under our 2014 Long Term Incentive Plan ("LTIP").

Our Revolving Credit Facility

As of March 31, 2018, our credit agreement had a borrowing base of $1.5 billion, an elected commitment amount of $900.0 million, lenders’ maximum facility commitments of $2.5 billion, and a maturity date of December 19, 2021. The credit agreement permits RSP Permian L.L.C., a wholly-owned subsidiary of the Company ("RSP LLC"), to make payments to the Company to enable it to pay principal, premium (if any) and interest on our existing senior notes, provided no default has occurred, and to allow RSP LLC to guarantee the existing senior notes.

The amount available to be borrowed under our Revolving Credit Facility is subject to a borrowing base that is redetermined semiannually each May and November and depends on the volumes of our proved oil, NGLs and natural gas reserves, estimated cash flows from these reserves and our commodity hedge positions. As of March 31, 2018, we

had $445.0 million of borrowings and $1.9 million of letters of credit outstanding under our Revolving Credit Facility and $453.1 million of borrowing capacity. In the event of any future offerings of senior unsecured notes issued or guaranteed by RSP LLC, the borrowing base under our Revolving Credit Facility will be automatically reduced by an amount equal to 0.25 multiplied by the aggregate principal amount of notes issued or guaranteed on the date of such issuance.
Our Revolving Credit Facility is secured by liens on substantially all of our properties and guarantees from our subsidiaries other than any subsidiary that we have designated as an unrestricted subsidiary.

Our Revolving Credit Facility contains restrictive covenants that may limit our ability to, among other things:

•incur additional indebtedness;

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- make loans to others;
- make investments;
- enter into mergers;
- make or declare dividends;
- enter into commodity hedges exceeding a specified percentage or our expected production;
- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

Our Revolving Credit Facility also requires us to maintain the following two financial ratios:

- a working capital ratio, which is the ratio of consolidated current assets (includes unused commitments under our Revolving Credit Facility and excludes restricted cash and derivative assets) to consolidated current liabilities (excluding the current portion of long term debt under our Revolving Credit Facility and derivative liabilities), of not less than 1.0 to 1.0; and
- a leverage ratio, which is the ratio of the sum of all of the Company's debt to the consolidated EBITDAX (as defined in our Revolving Credit Facility) for the four fiscal quarters then ended, of not greater than 4.25 to 1.0.

We were in compliance with such covenants and ratios as of March 31, 2018.

Principal amounts borrowed under our Revolving Credit Facility are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing at a Eurodollar rate or at the adjusted base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR plus an applicable margin depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's referenced rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin depending on the percentage of our borrowing base utilized, plus a commitment fee charged on the undrawn commitment amount. On March 31, 2018, our weighted average interest rate was approximately 3.9%.

See Note 6 in the notes to our consolidated financial statements for a further discussion of our Revolving Credit Facility.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, NGLs and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our revenues are subject to market risk and are dependent on the pricing we receive for our oil, NGLs and natural gas production. Pricing for oil, NGLs and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. Our realized prices are primarily driven by the prevailing prices for oil and the prevailing spot prices for NGLs and natural gas. We use derivative contracts to reduce our exposure to the changes in the prices of these commodities. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with projected production levels. We do not use these instruments to engage in trading activities, and we do not speculate on commodity prices.

The fair value of our derivative contracts as of March 31, 2018 was a net liability of $25.6 million. For information regarding the terms of these hedges and open positions, see Note 4 in the notes to our consolidated financial statements.

Counterparty and Customer Credit Risk

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such

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counterparties as we deem appropriate. The counterparties to our derivative contracts currently in place are lenders under our Revolving Credit Facility and have investment grade ratings.

Our principal exposures to credit risk are through receivables arising from joint operations and receivables from the sale of our oil, NGLs and natural gas production due to the concentration of our oil, NGLs and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit quality of our customers is high.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

Our exposure to interest rate changes related primarily to borrowings under our Revolving Credit Facility. Interest is payable on borrowings under the Revolving Credit Facility based on a floating rate as more fully described in Note 6 in the notes to our consolidated financial statements. At March 31, 2018, we had $445.0 million in borrowings outstanding under the Revolving Credit Facility that are subject to interest rate risk, and the weighted average interest rate for such borrowings was approximately 3.9%. Assuming no change in the amount outstanding, a 1.0% increase or decrease in the assumed weighted average interest rate would result in an increase or decrease in our interest expense of approximately $4.5 million. We currently do not engage in any interest rate hedging activity.

Item 4. Controls And Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of March 31, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of March 31, 2018 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the three months ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

From time to time, we are party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment related disputes. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity.

Item 1A. Risk Factors.

In addition to the risk factors set forth below and the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the factors discussed in "Part I, Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or results of operations.

Set forth below are certain material changes to the Risk Factors disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017:

Because the exchange ratio is fixed and because the market price of Concho common stock may fluctuate, our stockholders cannot be certain of the precise value of any merger consideration they may receive in the Merger.
At the time the Merger is completed, each issued and outstanding eligible share of our common stock will be converted into the right to receive the merger consideration of 0.320 of a share of Concho common stock. The exchange ratio for the merger consideration is fixed, and there will be no adjustment to the merger consideration for changes in the market price of Concho common stock or our common stock prior to the completion of the Merger. If the Merger is completed, there will be a time lapse between the date of signing the Merger Agreement and the date on which our stockholders who are entitled to receive the merger consideration actually receive the merger consideration. The market value of shares of Concho common stock may fluctuate during this period as a result of a variety of factors, including general market and economic conditions, changes in Concho's businesses, operations and prospects and regulatory considerations. Such factors are difficult to predict and in many cases may be beyond the control of Concho and us. The actual value of any merger consideration received by our stockholders at the completion of the Merger will depend on the market value of the shares of Concho common stock at that time. This market value may differ, possibly materially, from the market value of shares of Concho common stock at the time the Merger Agreement was entered into or at any other time. Our stockholders should obtain current stock quotations for shares of Concho common stock and for shares of our common stock.

The Merger may not be completed and the Merger Agreement may be terminated in accordance with its terms.
The Merger is subject to a number of conditions that must be satisfied or waived prior to the completion of the Merger, including approval of the Merger Agreement by our stockholders. These conditions to the completion of the Merger may not be satisfied or waived in a timely manner or at all, and, accordingly, the Merger may be delayed or may not be completed.

Moreover, if the Merger is not completed by October 31, 2018, either Concho or RSP Inc. may choose not to proceed with the Merger, and the parties can mutually decide to terminate the Merger Agreement at any time, before or after stockholder approval. In addition, Concho and RSP Inc. may elect to terminate the Merger Agreement in certain other circumstances as further detailed in the Merger Agreement.

The Merger Agreement limits our ability to pursue alternatives to the Merger.

The Merger Agreement contains provisions that may discourage a third party from submitting a competing proposal that might result in greater value to our stockholders than the Merger, or may result in a potential competing acquirer of the Company, proposing to pay a lower per share price to acquire the Company than it might otherwise have proposed to pay. These provisions include a general prohibition on us from soliciting or, subject to certain exceptions relating to the exercise of fiduciary duties by our board, entering into discussions with any third party regarding any competing proposal or offer for a competing transaction.

Failure to complete the Merger could negatively impact the price of shares of our common stock, as well as our future businesses and financial results.

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The Merger Agreement contains a number of conditions that must be satisfied or waived prior to the completion of the Merger. There can be no assurance that all of the conditions to the completion of the Merger will be so satisfied or waived. If these conditions are not satisfied or waived, we will be unable to complete the Merger.

If the Merger is not completed for any reason, including the failure to receive the required approval of our stockholders, our businesses and financial results may be adversely affected, including as follows:

- we may experience negative reactions from the financial markets, including negative impacts on the market price of our common stock;
- the manner in which customers, vendors, business partners and other third parties perceive the Company may be negatively impacted, which in turn could affect our marketing operations or our ability to compete for new business or obtain renewals in the marketplace more broadly;
- we may experience negative reactions from employees; and
- we will have expended time and resources that could otherwise have been spent on our existing businesses and the pursuit of other opportunities that could have been beneficial to the Company, and our ongoing business and financial results may be adversely affected.

In addition to the above risks, if the Merger Agreement is terminated and our board seeks an alternative transaction, our stockholders cannot be certain that we will be able to find a party willing to engage in a transaction on more attractive terms than the Merger. If the Merger Agreement is terminated under specified circumstances, we may be required to pay Concho a termination fee, reverse termination fee or other termination-related payment.

We will be subject to business uncertainties while the Merger is pending, which could adversely affect our businesses. Uncertainty about the effect of the Merger on employees and customers may have an adverse effect on the Company. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter and could cause customers and others that deal with us to seek to change their existing business relationships with us. Employee retention at the Company may be particularly challenging during the pendency of the Merger, as employees may experience uncertainty about their roles with Concho following the Merger. In addition, the Merger Agreement restricts us from entering into certain corporate transactions and taking other specified actions without the consent of Concho, and generally requires us to continue our operations in the ordinary course, until completion of the Merger. These restrictions may prevent us from pursuing attractive business opportunities that may arise prior to the completion of the Merger.

We will incur significant transaction and Merger-related costs in connection with the Merger, which may be in excess of those anticipated by us.

We have incurred and expect to continue to incur a number of non-recurring costs associated with negotiating and completing the Merger, combining the operations of the two companies and achieving desired synergies. These fees and costs have been, and will continue to be, substantial. The substantial majority of non-recurring expenses will consist of transaction costs related to the Merger and include, among others, employee retention costs, fees paid to financial, legal and accounting advisors, severance and benefit costs and filing fees. Many of these costs will be borne by us even if the Merger is not completed.

Completion of the Merger may trigger change in control or other provisions in certain agreements to which the Company is a party.

The completion of the Merger may trigger change in control or other provisions in certain agreements to which we are a party. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if we are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to us.

We may be a target of securities class action and derivative lawsuits which could result in substantial costs and may delay or prevent the Merger from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into merger agreements. Even if the lawsuits are without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative

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impact on our liquidity and financial condition. Additionally, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Merger, then that injunction may delay or prevent the Merger from being completed, which may adversely affect business, financial position and results of operation. Currently, we are unaware of any securities class action lawsuits or derivative lawsuits having been filed in connection with the Merger.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's repurchase of our common stock during the three months ended March 31, 2018:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased under the Plans or Programs
January 1, 2018 - January 31, 2018	69,971	$ 41.17	—	$ —
February 1, 2018 - February 28, 2018	76,194	34.12	—	—
March 1, 2018 - March 31, 2018	25,169	38.97	—	—
Total	171,334	$ 37.71	—	$ —

(1) These shares were withheld from employees to satisfy statutory tax withholding obligations arising upon the vesting of restricted shares under the LTIP.

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Item 6. Exhibits.

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on January 29, 2014).
3.2	Amended and Restated Bylaws of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 21, 2016).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company’s Registration Statement on Form S-1/A (File No. 333-192268) filed with the SEC on January 13, 2014).
4.2	Registration Rights Agreement, dated as of January 23, 2014, among RSP Permian, Inc., RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, ACTOIL, LLC, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on January 29, 2014).
4.3	Stockholders’ Agreement, dated as of January 23, 2014, among RSP Permian, Inc., RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on January 29, 2014).
4.4	Indenture, dated as of September 26, 2014, by and among the Company, RSP Permian, L.L.C. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 2, 2014).
4.5	Form of Senior Note due 2022 (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 2, 2014).
4.6	Registration Rights Agreement, dated as of August 10, 2015, by and among the Company, RSP Permian, L.L.C. and Goldman, Sachs, & Co. (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on August 12, 2015).
4.7	Stockholder’s Agreement, dated as of November 28, 2016, by and between the Company and Kayne Anderson Capital Advisors, LP (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 13, 2016).
4.8	Registration Rights Agreement, dated as of November 28, 2016, by and between the Company and Silver Hill Energy Partners Holdings, LLC (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 13, 2016).
4.9	Indenture, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 27, 2016).
4.10	Form of Senior Note due 2025 (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 27, 2016).
4.11	Registration Rights Agreement, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC, and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 27, 2016).
4.12	Registration Rights Agreement, dated as of March 1, 2017, by and between the Company and Silver Hill Energy Partners II, LLC (incorporated by reference to Exhibit 4.3 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 13, 2016).
31.1(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Executive Officer.

31.2(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Financial Officer.
32.1(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Extension Schema Document.
101.CAL(a)	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF(a)	XBRL Taxonomy Extension Definition Linkbase Document.

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101.LAB(a) XBRL Taxonomy Extension Label Linkbase Document.
101.PRE(a) XBRL Taxonomy Extension Presentation Linkbase Document.
(a) Filed herewith.
(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

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SIGNATURES

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

RSP PERMIAN, INC.

By:	/s/ Scott McNeill
	Scott McNeill
	Chief Financial Officer and Director
	(Principal Financial Officer)
Date:	May 2, 2018

By:	/s/ Uma L. Datla
	Uma L. Datla
	Chief Accounting Officer
	(Principal Accounting Officer)
Date:	May 2, 2018